Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

May 31, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Daniel Cassel, Director of Generation
Keys Energy Services
1001 James Street
Key West, Florida 33041-6100

Re: Keys Energy Services Stock Island Power Plant
Combustion Turbine Unit 4 – GE LM6000 SPRINT
File No. 0870003-007-AC (PSD-FL-348)

Dear Mr. Cassel:

Enclosed are documents indicating the Department's intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Keys Energy Services for construction of a 48 megawatt simple cycle unit at the Stock Island Power Plant. The documents include: the "Intent to Issue Air Construction Permit;" the "Public Notice of Intent to Issue Air Construction Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven (7) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, Program Administrator, South Permitting at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 or Mr. Linero at 850/921-9523.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief,
Bureau of Air Regulation

TLV/aal

Enclosures

In the Matter of an
Application for Permit by:

Keys Energy Services (KEYS)
1001 James Street
Key West, Florida 33041-6100

Authorized Representative:
Mr. Daniel Cassel, Director of Generation

DEP File No. 0870003-007-AC
Draft Permit No. PSD-FL-348
KEYS Stock Island Power Plant
48 MW Combustion Turbine Unit 4

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD), copy of DRAFT Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, Keys Energy Services, applied on October 14, 2004 (application revised on April 13, 2005) to the Department for an air construction permit for a nominal 48 megawatt simple combustion turbine project at the Stock Island Power Plant near Key West, Monroe County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit is required.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120 569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6/2/05 to the persons listed:

Daniel Cassel, KEYS*
Edward Garcia, KEYS
Frederick Bryant, FMPA*
Susan Schumann, FMPA
Mayor, Key West
Chair, Monroe County BCC
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Ron Blackburn, DEP SD
Stanley Armbruster, P.E., B&V

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Mary L Stanley 6/2/05
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0870003-007-AC (PSD-FL-348)

KEYS Stock Island Power Plant Combustion Turbine Unit 4
Monroe County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Keys Energy Services to construct a nominal 48 megawatt (MW) simple cycle combustion turbine at the existing Stock Island Power Plant near Key West, Monroe County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of nitrogen oxides (NO_X) and particulate matter (PM/PM_{10}). The applicant's address is Keys Energy Services (KEYS), 1001 James Street, Key West, Florida 33041-6100.

The applicant proposes to construct a new combustion turbine-electrical generator (Combustion Turbine Unit 4). The primary components are: one nominal 48 MW General Electric LM6000 PC combustion turbine-electrical generator with spray intercooling (SPRINT); a 60-foot exhaust stack; a nominal 1,000,000 gallon fuel oil storage tank; a new water tank; and other associated support equipment.

Combustion Turbine Unit 4 will be permitted to operate 2,500 hours per year while firing low sulfur fuel oil (0.05 percent sulfur). Water injection into the combustion area will be practiced for NO_X control.

The Department has determined that BACT for NO_X is 42.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O_2) under the very special circumstances of this project including location, lack of natural gas supply, low annual emissions for the project, installation of a single unit, etc. This limit will be achieved by water injection. Future increases in hours of operation will require installation of a selective catalytic reduction (SCR).

Emissions of carbon monoxide (CO), PM/PM_{10}, sulfuric acid mist (SAM), sulfur dioxide (SO_2), and VOC will be minimized by the efficient, high-temperature combustion of low sulfur fuel oil. A BACT determination was not required for CO, SAM, SO_2, or VOC.

KEYS' estimates of maximum potential annual emissions from Combustion Turbine Unit 4 are summarized in the following table. Actual emissions will be substantially less than estimated because much of the operation will be under low load conditions. For example, KEYS estimates that if it actually operates the unit for 2,500 hours per year, emissions will actually be less than 60 tons per year of NO_X considering low load versus the estimate of 95 given below

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	34	100	No
Pb	0.013	0.6	No
NO_X	95	40	Yes
PM/PM_{10}	31/31	25/15	Yes
SO_2	30	40	No
SAM	<7	7	No
VOC	7	40	No

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park (i.e. PSD Class II Areas) Therefore; multi-source modeling was not required for ambient air quality standards Class II increments.

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida 32399-2400 Telephone: 850/488-0114 Fax: 850/922-6979	Dept. of Environmental Protection Southeast District Office 400 North Congress Avenue West Palm Beach, FL 33416-5425 Telephone: 561/681-6600 Fax: 561/681-6790	Dept. of Environmental Protection South District Branch Office 2796 Overseas Highway, Suite 221 Marathon, Florida 33050 Telephone: 305/289-2310

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Program Administrator, South Permitting Section, Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/Air/permitting/construction/stockisland.htm

PERMITTEE:

Keys Energy Services
1001 James Street
Key West, Florida 33401-6100

ARMS Permit No.	0870003-007-AC
PSD Permit No.	PSD-FL-348
SIC No.	4911
Expires:	July 31, 2007

Authorized Representative:
Daniel Cassel
Director of Generation

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality. The proposed project authorizes the installation of one nominal 48 megawatts, fuel oil-fired, simple cycle combustion turbine-electrical generator. This project additionally authorizes the installation of a nominal 1,000,000 gallon fuel oil storage tank and an additional water tank.

The project will be located at the Stock Island Power Plant near Key West, Monroe County. The physical address of the facility is 6900 Front Street, Stock Island. UTM coordinates for this facility are Zone 17: 425.65 km E: 2716.67 km N.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD	Best Available Control Technology (BACT) Determination
Appendix GC	General Conditions

Michael G. Cooke, Director
Division of Air Resource Management

Date:

FACILITY DESCRIPTION

The existing Stock Island Plant consists of two nominal 8.8 MW diesel generators, one nominal 23.5 MW simple cycle combustion turbine, two nominal 19.8 MW simple cycle combustion turbines and miscellaneous unregulated units. The proposed project is to install one nominal 48 MW simple cycle combustion turbine-electrical generator, one nominal 1,000,000 gallon fuel oil storage tank, and a water tank.

NEW EMISSIONS UNITS

The proposed project will result in the following new emissions units.

EU ID No.	Emissions Unit Description
011	General Electric LM 6000 PC SPRINT Combustion Turbine-Electrical Generator
012	One nominal 1,000,000 gallon Distillate Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

Title III HAPs: This facility is not a major source of hazardous air pollutants (Title III).

Title IV Acid Rain: This facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

Title V Major Source: This facility is a Title V major source of air pollution.

PSD Major Source: The project is located in an area designated as "attainment," "maintenance," or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is not one of the 28 PSD source categories, and is subject to the PSD applicability threshold of 250 tons per year. Potential emissions of at least one regulated pollutant exceed 250 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

NSPS Sources: The combustion turbine specified in this permit is also subject to regulation under the New Source Performance Standards for Stationary Gas Turbines, 40 CFR 60, Subpart GG and may be subject to Proposed Subpart KKKK.

NESHAP: The National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subpart YYYY for combustion turbines does not apply because the facility is not a major source of HAPS.

RELEVANT DOCUMENTS

- Air Construction/PSD Permit application received on October 14, 2004;
- First Department Request for Additional Information (RAI) dated November 10, 2004;
- Response to First RAI received on January 18, 2005;
- Supplement to First RAI Response received on February 18, 2005;
- Second Department RAI dated February 17, 2005;
- Response to Second RAI received on April 13, 2005; and
- Intent to Issue Air Construction/PSD Permit distributed May 23, 2005.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number 850/488-0114.

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the South District Office, Florida Department of Environmental Protection, 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3381. The phone number is 239/332-6975 and the fax number is 239/332-6969.

3. Terminology: The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code.

4. General Conditions: The owner and operator are subject to, and shall operate under the attached General Conditions listed in *Appendix GC* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified.

7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C.]

9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

10. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

11. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

12. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

This section of the permit addresses the following new emissions unit for the period during which the unit operates for 2,500 hours or less on a rolling 12-month total and with water injection only. Upon reaching the first rolling 12-month total of 2,501, section III.B. of this permit will supercede all conditions in this section(III.A.).

E.U. ID No.	Common Emission Unit Description
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). [Rule 62-212.400, F.A.C.]
2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.
   (a) **Subpart A, General Provisions**, including:
   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (c) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a preliminary determination subject to approval by EPA, that this regulation proposed on January 18, 2005 does not apply to this project.

Performance Restrictions

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]
4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.] (See III.B. for BACT if increased hours of operation.)

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)]

   {Permitting note: Pipeline natural gas is currently unavailable to the Keys.}

7. Hours of Operation: The combustion turbine shall operate no more than 2,500 hours based on a 12-month rolling total without installing a selective catalytic reduction (SCR) system. Exceeding this restriction shall require the installation and operation of an SCR system as required in III.B. [Applicant Request, Rules 62-210.200, (PTE) and 62-212.400(2)(g), F.A.C.]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request: Rule 62-4.070(3): Rule 62-212.400, F.A.C. (BACT)]

9. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

EMISSIONS CONTROLS

10. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering, confining, or applying water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_X emissions standards for the unit. [Applicant request: Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Future Selective Catalytic Reduction (SCR): The permittee shall design and build the project to facilitate and not to hamper or preclude the future installation of the SCR system. The combustion turbine may operate without the use of the SCR system for an initial period during which the total

hours of operation do not exceed 2,500 during any 12-month rolling total. [Design and Rule 62-212.400, F.A.C.]

13. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only, and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	42 ppmvd @ 15% O_2	75.9	94.9
CO	30 ppmvd @ 15% O_2	33.0	41.0
SO_2	0.05 percent sulfur fuel oil	23.6	29.5
SAM	0.05 percent sulfur fuel oil	5.4	6.8
PM/PM_{10}	VE = 10% as surrogate	25.0 (front and back)	31.3
PM/PM_{10}	VE = 10% as surrogate	13.9 (front half)	17.4
VOC	16 ppmvd @ 15% O_2	10.0	12.6

Note: Annual emissions, for the purposes of this table only, are based on a 41° F temperature and 2,500 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 30.0 ppmvd @15% O_2. CO emissions shall not exceed 33.0 pounds per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit.
[Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

This emissions limit applies during the initial phase of operation when the combustion turbine operates no more than 2,500 hours based on a 12-month rolling total:

NO_X emissions from the combustion turbine shall not exceed a BACT emission limit of 42 ppmvd @15% O_2 during initial and annual tests nor exceed 42.0 ppmvd @15% O_2 on a 24-hour block average while firing fuel oil. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

{Permitting note: Pipeline natural gas is currently unavailable to the Keys. However, for a similar unit operating on natural gas and for a comparable number of hours, a BACT limit would likely be set at 15 ppmvd @ 15% O_2.}

A. COMBUSTION TURBINE (EU 011) WATER INJECTION ONLY & ≤ 2,500 HOURS

17. Particulate Matter (PM/PM_{10}) and Visible Emissions (VE)

Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM10 emission limits. [Rules 62-4.070(3) and 62-212.400, F.A.C. (PSD Applicability)]

18. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

Emissions of SAM and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.8 and 29.5 tons per year, respectively. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the fuel records specified by this permit.[Rules 62-4.070(3), and 62-212.400, F.A.C. (BACT)].

19. Volatile Organic Compounds (VOC):

VOC emissions from the combustion turbine shall not exceed 16.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 10.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.A. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

20. Definitions

(a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

(b) *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(246), F.A.C.]

(c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

(d) *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

21. Startup, Shutdown, Malfunction: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing: (1) best operational practices to minimize

emissions are adhered to, and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report. [Rule 62-210.700(1) and (6), F.A.C.]

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period.
[Design: Rule 62-210.700(1) and (5), F.A.C.]

(b) During all startups, shutdowns, and malfunctions, the NO_x continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods. [Rule 62-210.700(1) and (5), F.A.C.]

(c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Design: Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

22. Prohibition: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

23. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

24. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

(a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

(b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

(c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines; and

(d) EPA Method 25 or 25A - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions).

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

25. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

26. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.]

27. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year. [Rule 62-297.310(7)(a), F.A.C.]

28. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

29. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed. [Rule 62-297.310(7)(a)4., F.A.C.]

30. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

31. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

32. Applicable Test Procedures

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4)(b), F.A.C.]

(c) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4)(d), F.A.C.]

33. Determination of Process Variables

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

34. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

35. NO_X CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the

requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

36. NO_X CEMS Data Requirements:

(a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

(b) Data Collection. Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

(c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition 41 of this permit.

(d) Data Exclusion. As provided in III.A. 21-22., valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

37. Hours of Operation: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including hours during startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

38. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

39. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

40. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation (including hours during startups, shutdowns, and malfunctions) shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

41. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

42. Excess Emissions Reporting:

(a) If excess NO_X or visible emissions occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

(b) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual to the Compliance Authority.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart GG, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

(c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j)(1)]

43. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

44. Hours of Operation: Within ten working days following the first consecutive 12-month period in which the hours of operation exceed 2,500, the permittee shall notify the Compliance Authority. The notification shall include a summary of operation for the last 12 months, and the expected date of initial operation of the SCR system for the control of NO_X as required by III.B. [Rule 62-204.070, F.A.C., and Applicant Request]

B. COMBUSTION TURBINE (EU 011) WATER INJECTION AND SCR & > 2,500 HOURS

This section of the permit addresses the following new emissions unit upon exceeding 2,500 hours or operation on a 12-month rolling total and thereafter. Upon exceeding 2,500 hours, the provisions of III.B. superceed III.A. for the rest of the operating life of the unit. BACT is water injection and SCR.

E.U. ID No.	COMMON EMISSION UNIT DESCRIPTION
011	General Electric LM 6000 PC Sprint Combustion Turbine-Electrical Generator

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for nitrogen oxides (NO_X), and particulate matter (PM_{10}). Practicably enforceable limits have been established for sulfur dioxide (SO_2), and sulfuric acid mist (SAM) to avoid BACT determinations for these pollutants. [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (a) **Subpart A, General Provisions**, including:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (d) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (e) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** The Department has made a preliminary determination, subject to approval by EPA, that this regulation proposed on January 18, 2005 does not apply to this project.

PERFORMANCE RESTRICTIONS

3. Combustion Turbine: The permittee is authorized to install, tune, operate and maintain one simple cycle combustion turbine-electrical generator with spray intercooling and water injection (General Electric Model LM6000 PC SPRINT). The unit is designed to produce approximately 48 MW of electrical power at ISO conditions. [Applicant Request]

4. Permitted Capacity: The heat input to the combustion turbine from firing No. 2 fuel oil shall not exceed 434 MMBtu per hour (LHV) based on the following: 100% base load, lower heating value of No. 2 fuel oil, and a compressor inlet air temperature of 41° F. If different from the information provided in accordance with Specific Condition III.A.4, the permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon compressor conditions and the combustion turbine characteristics. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves on file with the Department.
   [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determination and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle operation which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.]

6. Allowable Fuels: Only distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight shall be used in the combustion turbine. The permittee shall demonstrate compliance with the fuel sulfur limit by keeping the records specified in this permit. Total fuel usage shall no exceed 13,600,000 gallons of fuel oil during any consecutive 12 months. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)].

7. Hours of Operation: The combustion turbine may operate 8,760 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (PTE)]

8. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

EMISSIONS CONTROLS

10. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering, confining, or applying water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

11. Water Injection Technology: The permittee shall install, calibrate, tune, operate, and maintain a water injection system designed to achieve the permitted NO_x emissions standards for the unit in conjunction with the SCR system.
[Applicant request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. Selective Catalytic Reduction (SCR): Within two months after exceeding the 12-month rolling total of 2,500 operating hours, the permittee shall install, calibrate, tune operate and maintain an SCR system designed to achieve the permitted NOx emissions standards for the unit in conjunction with the water injection system. [Design and Rule 62-212.400, F.A.C.]

13. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

EMISSIONS STANDARDS

14. Summary: The following table summarizes the emissions standards for each pollutant and total emissions in lb/hr and TPY for informational and convenience purposes (PTE) only and shall not be considered permit limits. This table does not supersede any of the terms or conditions of this permit.

Pollutant	Emission Standard/Limit	Emissions (lb/hr)	Emissions (TPY)
NO_X	9 ppmvd @ 15% O_2 24-hr block average	16.3	36.0
CO	20.0 ppmvd @ 15% O_2	20.0	44.2
SO_2	0.05 percent sulfur fuel oil	23.6	39.9
SAM	0.05 percent sulfur fuel oil	5.4	6.9
PM/PM_{10}	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
PM	VE = 10% as surrogate 0.05 percent sulfur fuel oil	25.0	109.5
VOC	8.0 ppmvd @ 15% O_2	5.0	11.0

Note: Annual emissions, for the purposes of this table only, are based on an ambient temperatures and the equivalent of 4,420 hour of full load operation. PM/PM_{10} estimates are based on the equivalent of 8,760 hours of full load operation.

15. Carbon Monoxide (CO):

CO emissions from the combustion turbine shall not exceed 20.0 ppmvd @15% O_2. CO emissions shall not exceed 20.0 lbs per hour. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400, F.A.C. (PSD Avoidance)]

16. Nitrogen Oxides (NO_X):

The combustion turbine and SCR system shall be designed and constructed to meet an emission limit of 5.0 ppmvd @15% O_2. This shall be demonstrated during each initial test following installation of new catalyst. During normal operation, NO_x emissions shall not exceed 9.0 ppmvd @15% O_2 on a 24-hour block average. The permittee shall demonstrate compliance with this standard by conducting performance tests and emissions monitoring in accordance with 40 CFR Part 60 Subpart GG and based on a 24-hour block average for data collected from the continuous emissions monitor.
[Rule 62-212.400, F.A.C. (BACT)]

{Permitting note: The 5.0 ppmvd value reflects BACT. The 9.0 ppmvd value is based on the fuel use limitation that would limit NO_x emissions to less than 40 tons per year. The Department will revise the higher long term limit downward in conjunction with any future applications that will increase fuel use above 13,600,000 gallons per year.}

17. Ammonia (NH_3)

The ammonia slip rate shall be limited to 10.0 ppmvd @ 15% O_2.
[Rule 62-212.400, F.A.C. (BACT).

B. COMBUSTION TURBINE (EU 011) WATER INJECTION AND SCR & > 2,500 HOURS

18. Particulate Matter (PM/PM_{10})

    Emissions of PM and PM_{10} shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. Visible emissions from the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. This work practice standard is established as a means of ensuring compliance with the BACT PM/PM_{10} emission limits. [Rule 62-212.400, F.A.C. (PSD Applicability)]

19. Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

    Emissions of SAM, and SO_2 shall be limited by the use of 0.05 percent sulfur fuel oil (or superior fuel oil) and good combustion techniques as specified in this permit. SAM and SO_2 emissions shall not exceed 6.9 and 39.9 tons per year, respectively. Compliance with the SO_2 limit provides assurance that SAM emissions stay within permitted limits. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the records specified by this permit. [Rule 62-212.400, F.A.C. (BACT)].

20. Volatile Organic Compounds (VOC):

    VOC emissions from the combustion turbine shall not exceed 8.0 ppmvd corrected to 15% oxygen for each fuel. VOC emissions shall not exceed 5.0 pounds per hour. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting initial tests in accordance with EPA Methods 25 and/or 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Section III.B. of this permit. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, NESHAP, or Acid Rain programs.}

21. Definitions

    (a) *Excess Emissions* are defined as emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

    (b) *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(246), F.A.C.]

    (c) *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(231), F.A.C.]

    (d) *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

22. Startup, Shutdown, Malfunction: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing: (1) best operational practices to minimize emissions are adhered to, and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A written report summarizing each malfunction resulting in excess emissions shall be submitted in a quarterly report. [Rule 62-210.700(1) and (6), F.A.C.]

   (a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for more than 2 hours in any 24-hour block averaging period.
   [Design; Rule 62-210.700(1) and (5), F.A.C.]

   (b) During all startups, shutdowns, and malfunctions, the NO_X continuous emissions monitoring System (CEMS) shall monitor and record emissions. Up to 2 hours (120 minutes) of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. However, only data obtained during startups, shutdowns, and documented malfunctions may be used for the 2 hour exclusion period. Other arbitrary high readings may not be excluded from compliance averaging periods. [Rule 62-210.700(1) and (5), F.A.C.]

   (c) A documented malfunction means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile, or electronic mail. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
   [Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

23. Prohibition: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

EMISSIONS PERFORMANCE TESTING

24. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. KEYS shall advise the Department of any requirements within the cited rule that would be incompatible with the operation of an SCR system or unadvisable due to storm design criteria. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

25. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

   (a) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources;

   (b) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources;

   (c) EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure); or EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.

   (d) EPA Method 25 or 25A

(e) - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions); and

(f) Conditional Test Method 027 – Measurement of Ammonia Slip.

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure specified in Rule 62-297.620, F.A.C.

26. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to initial NSPS performance tests and at least 15 days prior to any other required tests. [40 CFR 60.7, 40 CFR 60.8 and Rule 62-297.310(7)(a)9., F.A.C.]

27. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NO_X, VOC, ammonia slip and visible emissions. Initial NO_X performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG and shall also be converted into units of the NSPS emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.]

28. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for NO_X, CO, and visible emissions from the combustion turbine for each fuel. Testing for ammonia slip is required during the first scheduled annual performance tests after the cumulative hours of operation exceed 1,500 actual hours starting from the initial installation of the SCR catalyst. Thereafter, ammonia testing is required during the first scheduled annual performance tests after subsequent cumulative 1,500 hours of operation or after regeneration, replacement or addition to the SCR catalyst system. If conducted at permitted capacity, NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). In the event that the operation of the CT is less than 400 hours per year, annual testing is not required for that year. [Rule 62-297.310(7)(a), F.A.C.]

29. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NO_X, and visible emissions from the combustion turbine. VOC emission tests are not required prior to permit renewal provided the CO emission standards are met. Testing for ammonia slip meeting the requirements of Condition 26, Annual Performance Tests will meet the requirements of this condition. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

30. Tests After Major Repairs or Replacements: The Department may require that additional compliance testing be conducted within 90 days after major repairs or replacements are performed. [Rule 62-297.310(7)(a)4., F.A.C.]

31. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100

percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

32. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

33. Applicable Test Procedures

    (a) Required Sampling Time.

        1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

        2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

    (b) Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4)(b), F.A.C.]

    (c) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4)(d), F.A.C.]

34. Determination of Process Variables

    (a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

    (b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

35. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct

compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
[Rule 62-297.310(7)(b), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

36. <u>NO_X CEMS</u>: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NO_X and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NO_X monitoring devices shall comply with the requirements of 40 CFR 60.334(b) for 40 CFR Part 75 monitoring systems. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

37. <u>NO_X CEMS Data Requirements</u>:

(a) Installation. The CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 60.7(a)(5), 40 CFR 60.13, and 40 CFR 60.334(b).

(b) Data Collection. Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. A valid hour is one in which at least 1 data point is recorded in each quadrant during which the unit was operating.

(c) Data Reporting: Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 24-hour block averaging period. The block averaging period shall run from midnight to midnight of each day. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of a 24-hour block of all valid hourly emission rates. A minimum of 1 valid hour shall be required to calculate a 24-hour block average. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required in specific condition 42 of this permit.

(d) Data Exclusion. As provided in III.B. 21-22, valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit. Up to 2 hours of monitoring data during any 24-hour block averaging period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-297.520, F.A.C and 40 CFR 60.7].

38. <u>Hours of Operation</u>: Using a component of the gas turbine control system, the permittee shall monitor and record the hours of gas turbine operation. Within five working days following the end of each calendar month, the permittee shall record the total hours of operation (including startups, shutdowns, and malfunctions) for the current month, and the total hours of operation for the current

month plus the preceding 11 months.
[Rule 62-204.070, F.A.C., and Applicant Request]

COMPLIANCE DEMONSTRATIONS

39. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

40. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limits for fuel oil specified in this permit by maintaining records required by 40 CFR 60.334 and 60.335 and the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

41. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and amount of each fuel fired for the combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. All hours of operation shall be included in the demonstration of compliance with the 12-month fuel usage limitations. Information recorded and stored as an electronic file shall be available for inspection and/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

42. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

43. Excess Emissions Reporting:

    (a) If excess NO_X or visible emissions occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    (b) NSPS Semi-Annual Reports. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual to the Compliance Authority.

    {Note: If there are no periods of excess emissions as defined in NSPS Subpart GG, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

    (c) SIP Quarterly Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of NOx emissions in excess of the BACT permit standards at Specific Condition 16 following the NSPS format in 40

CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j)(1)]

44. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual fuel usage and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year.[Rule 62-210.370(2), F.A.C.]

DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
012	One distillate fuel oil storage tank for Combustion Turbine Unit 4 (approximately 1.0 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: As revised October 15, 2003, NSPS Subpart K does not apply to storage vessels which store a liquid with a vapor pressure less than 3.5 kPa.

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one, 1.0 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to Combustion Turbine Unit 4 or any other units on the site. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

   {Note: Emissions of VOC form this unit are estimated to be less than one ton per year.}

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT proposal discussed in the Technical Evaluation for this project for the rationale regarding the following BACT determination.

For operation less than 2,500 hours, the following BACT determination applies:

a. NO_X. - 42.0 ppm @ 15% O_2 (75.9 lb/hr) while firing oil.

   Continuous compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS and based on a 24-hr block average. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

b. PM/PM_{10} - distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight, and visible emissions $\leq$ 10% opacity, based on a 6-minute average.

   The sulfur fuel specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specification, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specification shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard (10%) shall be demonstrated by conducting tests in accordance with EPA Method 9.

c. The mass emission rate standards are based on a turbine inlet condition of 41° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

For operation 2,500 hours or greater, the following BACT determination applies:

a. NOx - 5 ppm @ 15% O_2 (8.9 lb/hr) while firing oil.

   Compliance with the NO_X standards shall be demonstrated by conducting tests in accordance with EPA Method 7E or Method 20. Tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

d. PM/PM_{10} - distillate fuel oil with a maximum sulfur content less than or equal to 0.05 percent by weight, and visible emissions $\leq$ 10% opacity, based on a 6-minute average.

   The sulfur fuel specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specification, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specification shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard (10%) shall be demonstrated by conducting tests in accordance with EPA Method 9.

b. The mass emission rate standards are based on a turbine inlet condition of 41° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator
South Permitting Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
Trina L. Vielhauer, Chief Bureau of Air Regulation	Michael G. Cooke, Director Division of Air Resources Management
Date	Date

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
    d. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Keys Energy Services
Stock Island Power Plant
Combustion Turbine Unit 4

48-Megawatt Simple Cycle Power Project

Monroe County

DEP File No. 0870007-AC (PSD-FL-348)

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting South

May 31, 2005

1. APPLICATION INFORMATION

Applicant Name and Address

Keys Energy Services
1001 James Street
Post Office Box 6100
Key West, Florida 33041-6100

Authorized Representative:
Daniel Cassel, Director of Generation

Processing Schedule

- Received Air Construction Permit/PSD application on October 14, 2004;
- Additional information requested November 10, 2004 and February 17, 2005;
- Received additional information on January 18, February 18, and April 13, 2005; and
- Intent to Issue Air Construction/PSD Permit distributed April 22, 2005.

Facility Description and Location

Keys Energy Services (KEYS) operates the Stock Island Power Plant, which is located at 6900 Front Street, Stock Island near Key West in Monroe County. The existing Stock Island Plant consists of two nominal 8.8 MW diesel generators, one nominal 23.5 MW simple cycle combustion turbine, two nominal 19.8 MW simple cycle combustion turbines and miscellaneous unregulated units. The location of the Stock Island Power Plant is shown in Figures 1 and 2.

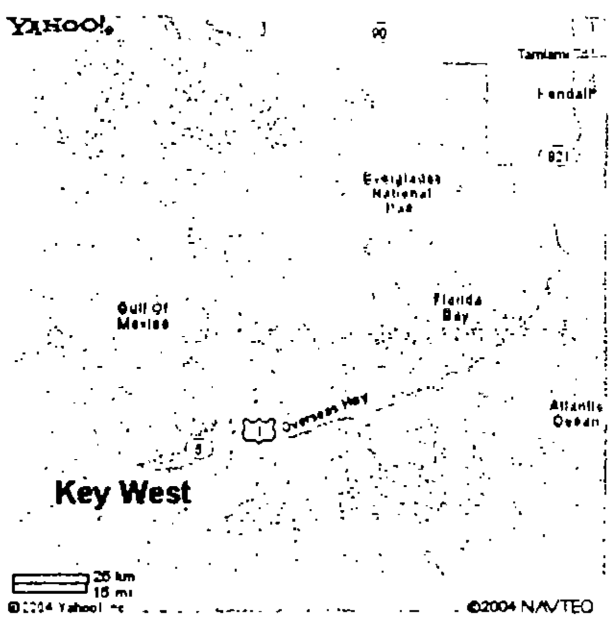

Figure 1. Location of Key West

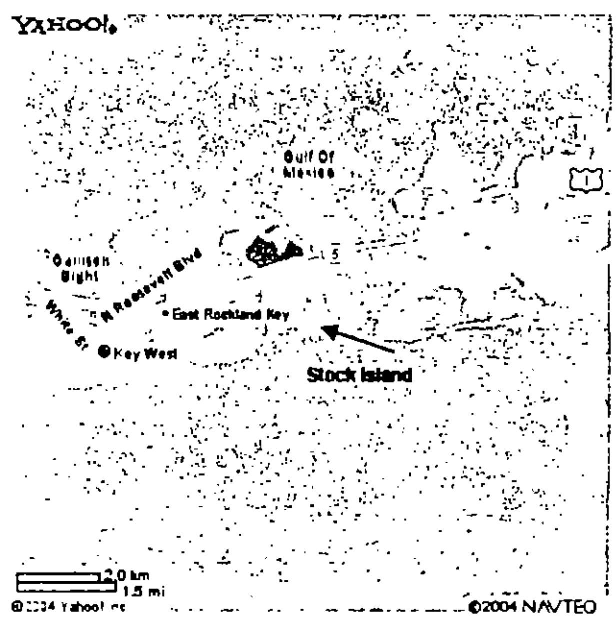

Figure 2. Location of Stock Island

The Stock Island Power Plant is located approximately 90 kilometers southwest from the Class I Everglades National Park.

Regulatory Categories

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year or because it is a Major Source of HAPs. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is a Major Facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The facility is not a steam electrical generating plant and is not subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a fuel oil-fired simple cycle unit consisting of the following equipment and specifications: one nominal 48 MW General Electric LM6000 PC SPRINT combustion turbine-electrical generator; a nominal 1 million gallon diesel fuel storage tank; a new water tank; and a minimum 60-foot exhaust stack with associated ducting, flow straightening and silencing. Combustion turbines are often referred to as "gas turbines". This refers to use of air (instead of steam) as the operating medium and not firing with natural gas. The less ambiguous term, combustion turbine, will be used in this review. Following are further details.

- Fuel: There is no natural gas infrastructure in extreme South Florida. KEYS proposes to use low sulfur (0.05% Sulfur) distillate oil. The applicant's original request was for 4,420 fuel equivalent hours of operation. The application has since been revised to request 2,500 hours per year of operation.
- Generating Capacity: The proposed combustion turbine has a nominal generating capacity of 48 MW. The actual range is approximately 40 to 50 MW for temperatures between 90 and 40 degrees (°F). This range is related to the higher density and mass flow of the working medium (air) at lower temperatures.
- Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of distillate oil at relatively high temperatures. Emissions of SAM and SO_2 will also be minimized by firing low sulfur distillate oil. NO_X emissions will be reduced by water injection into the combustor.

- Continuous Monitors: The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitor will be employed for demonstration of continuous compliance with the Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: The following summarizes the exhaust characteristics at 41 °F:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
No. 2 Fuel Oil	433.4 mmBtu/hour	41° F	~814° F	~555,000

Project Description

Refer to Figure 3 below.[1] A combustion turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 5 stage low pressure compressor (LPC) of the GE LM6000 PC SPRINT combustion turbine proposed for this project. The air is further compressed in the 14-stage high pressure compressor (HPC) to a pressure ratio of about 30 times atmospheric pressure. A portion of the compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 30 replaceable fuel nozzles.

The hot combustion gases are then diluted with additional cool air from the compressor and directed to the two-stage high pressure turbine (HPT) section and then the 5-stage low pressure turbine section. The power turbine is directly driven.

Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas is discharged at a temperature range of 760 to 860 °F and high excess oxygen and is normally available for additional energy recovery (such as in combined cycle configurations).

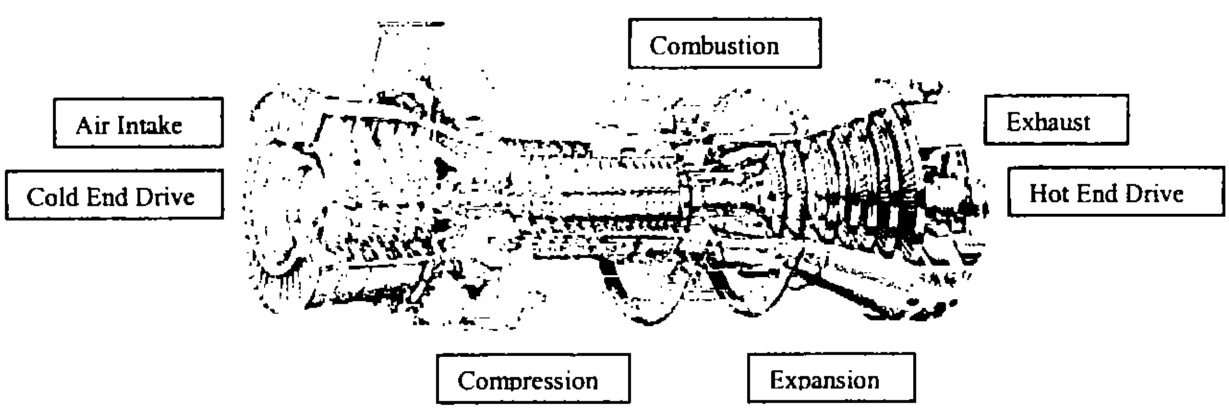

Figure 3. Key Components of the LM 6000 Simple Cycle Combustion Turbine

The particular model selected by the applicant has some very specific features including:

- Water Injection. This feature involves water injection into the combustor for the purpose of NO_X abatement. Greater power production is also realized by the additional mass flow.
- SPRay INTercooling (SPRINT™): This additional feature, known as the Sprint™ System, involves injecting fine water droplets into the LPC and HPC inlet plenums. This provides for better cooling of hot section components and allows higher firing temperatures to be realized in the combustor. This feature increases shaft power by approximately 12 percent (%) at 59 °F and 30% at 90 °F compared to a gas-fired LM 6000 PC practicing water injection.

Further process details are provided in the Draft determination of Best Available Control Technology (BACT) in Section 4.0 below.

Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's original (and revised) estimate of the annual emissions in tons per year from the proposed project.

Table 1. Applicant's Original (and Revised) Estimated Annual Emissions

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	34 (21)	100	No
Pb	0.013	0.6	No
NO_X	154 (76)	40	Yes
PM/PM_{10}	110 (31)	15/25	Yes
SO_2	48 (24)	40	Yes (No)
SAM	15 (<7)	7	Yes (No)
VOC	10 (6)	40	No

3. RULE APPLICABILITY

State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following rules in the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution

Chapter	Description
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project as originally proposed are required for NO_X, SO_2, SAM and PM/PM_{10}. Based on the revised application, determinations are required for NO_X, and PM/PM_{10}

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"Best Available Control Technology" or "BACT" - An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

a. *If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*

b. *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

3. *A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, in making the BACT determination, the Department shall give consideration to:

1. *Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).*
2. *All scientific, engineering, and technical material and other information available to the Department.*
3. *The emission limiting standards or BACT determinations of any other state.*
4. *The social and economic impact of the application of such technology.*

4.2 NO_X BACT Determination

4.2.1 Nitrogen Oxides Formation

Nitrogen oxides form in the combustion turbine process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In most combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation is depicted in Figure 4 which is from a General Electric discussion on these principles.

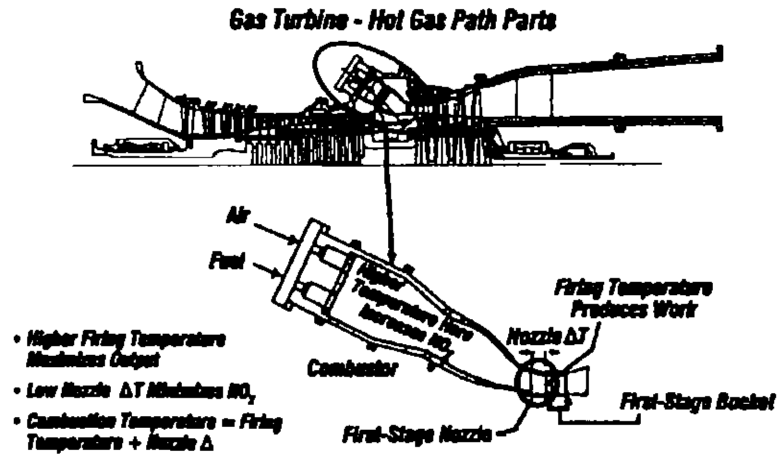

Figure 4 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 400 ppmvd @15% O_2 for a fuel oil-fired LM 6000 PC SPRINT combustion turbine (200 ppmvd for gas-firing).[2] The proposed NO_X controls will reduce these emissions significantly.

For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_X emissions from large utility gas turbines such as the GE7FA is approximately 120 ppmvd @15%O_2. This standard, applicable to combustion turbines built after 1977, constitutes the legal floor (absolute maximum NO_X value) in a "Top/Down" BACT determination.

More recently EPA proposed a new standard (40 CFR 60, Subpart KKKK) applicable to combustion turbines that commence construction after February 18, 2005. Proposed Subpart KKKK limits NO_X emissions from large fuel oil-fired combustion turbines to 1.2 pounds NO_X per megawatt-hour (lb/MWH). This equates to approximately 34 ppmvd @15% O_2.[3]

KEYS provided a letter to support their position that KEYS commenced construction on February 18, 2005 such that Subpart KKKK does not apply to the proposed project.[4] Notwithstanding the apparent agreement, the Department must consider the Subpart KKKK proposal in setting a BACT determination for this project, if it is not an applicable requirement.

4.2.2 Descriptions of Available NO_X Controls

Wet Injection

Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. GE does not presently guarantee emissions less than 42 ppmvd when firing fuel oil in an LM6000.

Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low Emissions (DLE)

Lean fuel combustion provides a theoretically lower flame temperature. Premixing of the air and fuel prior to entering the combustor can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The GE product for aeroderivative combustion turbines is called Dry Low Emissions (DLE). The features of the early DLE combustion system are shown in Figure 5. In contrast to other low emissions technologies, the lean pre-mix feature of the DLE combustor for aeroderivative engines functions even at low load. As previously mentioned, without DLE or water injection, NO_X would be approximately 200 and 400 ppmvd @15% O_2 on gas and oil respectively.

The first commercial installation of the DLE combustion system was on a 43 MW LM6000 gas fired combustion turbine in the mid-1990's at the Ghent power station in Belgium. It achieved emissions of 16 ppm NO_X, 6 ppm CO and 1 ppm unburnt hydrocarbons.

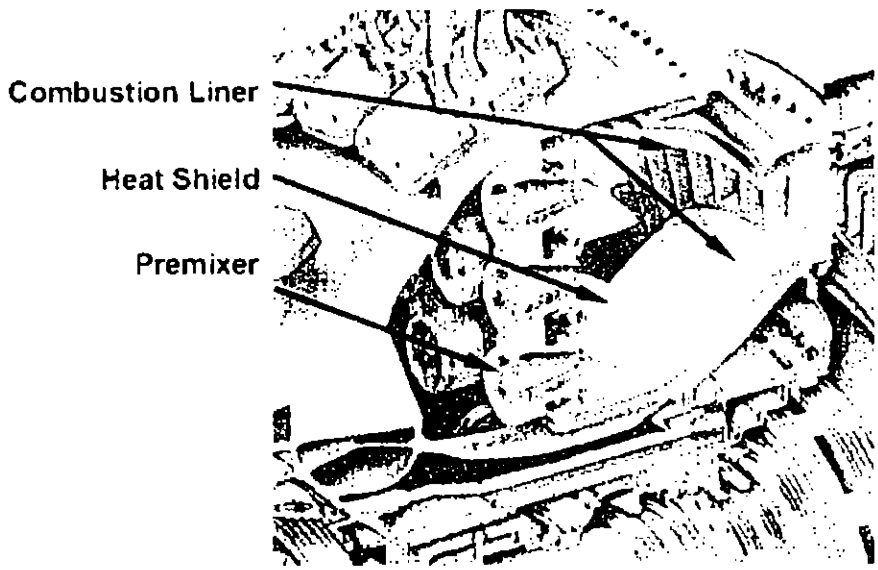

Figure 5 – Dry Low Emissions (DLE) Combustor

Orange Cogen installed two LM6000 PB combustion turbines in the mid-1990's to operate in combined cycle. Initially the units were required to achieve 25 ppmvd NO_X @15% O_2 while firing natural gas with a requirement to reduce emissions to 15 ppmvd several years after startup. Following is the time series developed from the most recent data available from the continuous emission monitoring record submitted quarterly by Orange CoGen to EPA. The values greater than 15 ppmvd are typically short-duration startups that are actually characterized by low mass (lb/hr) emissions during the given hours. The 15 ppmvd NO_x limits for these units are based on 3-hr averaging times, therefore it appears that they are meeting their permitted limits.

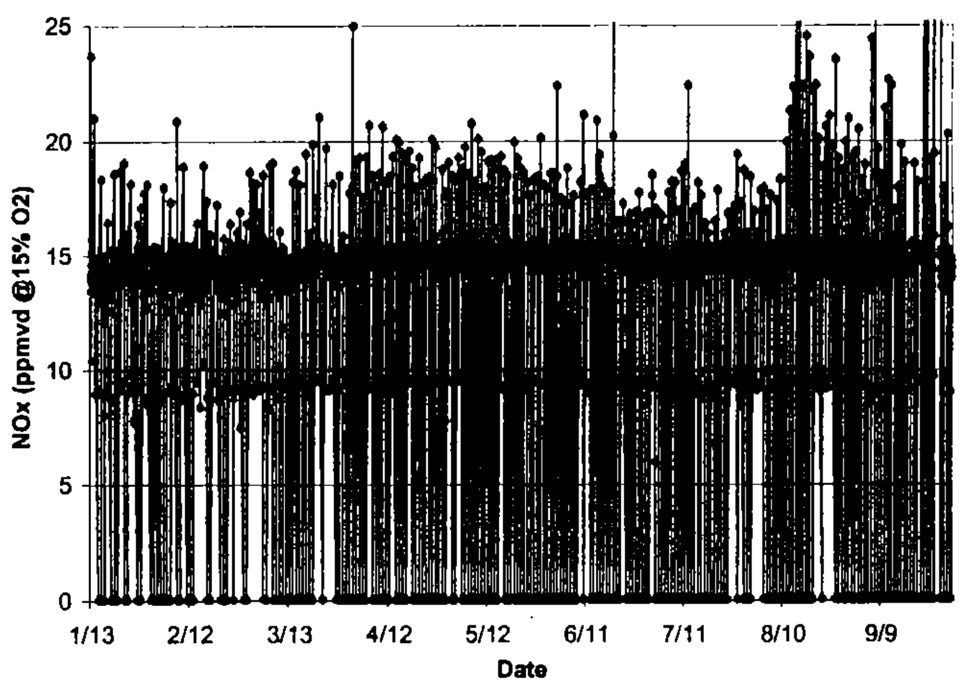

Figure 6 – NO_X Emissions from Orange CoGen LM6000 PB Gas-Fired Unit 1 (2004)

The DLE arrangement installed at Orange CoGen is not available on newer versions of LM 6000 combustion turbine. There is a newer version called DLE-II technology that is available on newer LM6000 PC and LM6000 PC SPRINT combustion turbines. According to GE sales and technical experts, the DLE-II is available with a 15 ppmvd guarantee while operating on natural gas.[5]

The DLE-II was designed to operate in conjunction with the higher power features of the newer versions of the LM 6000 PC and PC SPRINT. This was made possible by dispensing of a shroud in the combustion area that previously required cooling. The lower cooling requirement makes it possible to divert more air from the compressor to make a leaner air-fuel mixture for combustion.

DLE and DLN technologies are technically possible for oil-fired units. However they are more expensive and it is more difficult to reach the values achievable by DLN or DLE when using gas. According to the Siemens-Westinghouse website, their 45 MW SGT-800 combustion turbine (formerly ABB GTX100) with their 3rd generation DLE combustor can meet 25 ppmvd @15% O_2 when burning fuel oil.[6] It is not certain whether this is accomplished by wet injection or by the DLE feature.

Catalytic Combustion - XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[7] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[8] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[9] By now, five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[10] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not yet available for fuel oil-fired combustion turbines of the size of an LM 6000 PC SPRINT.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations. At high temperatures, V can contribute to ammonia oxidation forming more NO_X or forming nitrogen (N_2) without reducing NO_X according to:

$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$ and

$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$

For high temperature applications (hot SCR up to 1100 °F), such as large frame simple cycle turbines, special formulations or strategies are required.

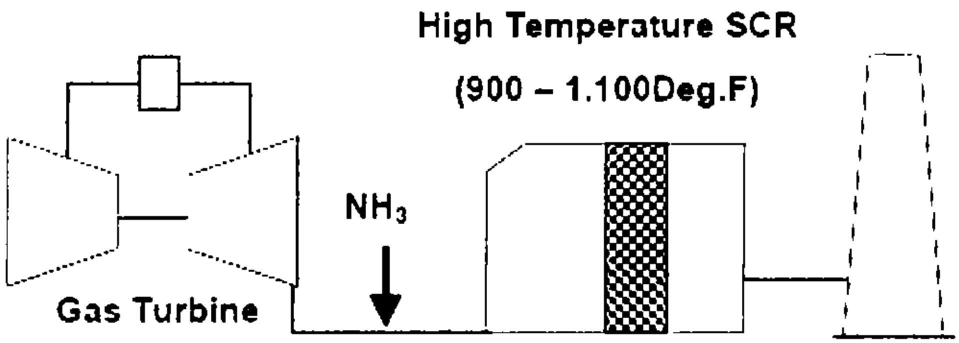

Figure 7 – High Temperature SCR Configuration for Simple Cycle Combustion Turbine

SCR technology has progressed considerably over the last decade. Zeolite catalyst was developed for high temperature applications. Such catalyst provided by Engelhard was involved in a failed application at the oil-fired simple cycle PREPA Cambalache project in Puerto Rico in the late 1990's. The permitted limit while firing fuel oil in the three nominal 83 MW ABB GT-11N was 9 ppmvd.[11]

There has been much debate regarding the reasons for the failure ranging from the use of fuel oil, its sulfur content of 0.15%, the nature of high temperature applications, water injection, the catalyst, etc. EPA allowed removal of the catalyst from the simple cycle units and installation of Low NO_X burners on some boilers located at the same facility to abate the NO_X increase. It is important to note that the permit application was submitted 11 years ago and improvements have since been made in high temperature SCR catalysts.

All of the catalyst suppliers presently offer formulations and strategies for applications for the moderate temperature range (760 – 860 °F) of SCR applications suitable for the LM6000 PC SPRINT. Hitachi offers a catalyst with a TiO_2 base and tungsten (WO_3) that Hitachi claims outperformed zeolite catalyst in accelerated durability tests.[12] The peak activity temperature (842 °F) for Hitachi's catalyst is virtually equal to the exhaust temperatures expected from the LM6000 PC SPRINT at full load. This temperature is less than experienced by the catalyst at the PREPA Plant (824 to 1014 °F).

The following figure reflects Hitachi's view of its high temperature TiO_2/WO_3 formulation compared with conventional low/middle temperature V catalyst and high temperature zeolite catalyst.

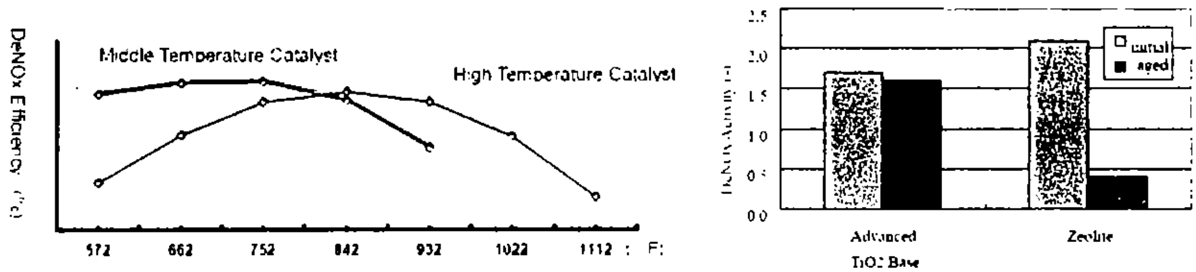

Figure 8 – High Temp TiO_2/WO_3 versus Mid-Temp V and High Temp Zeolite Catalysts

If this information is accurate, it certainly provides reason to believe that a possible cause is inherently shorter lifetime for zeolite formulations. According to Hitachi the accelerated zeolite deterioration observed during its durability tests was caused by the water concentration in exhaust gas that impacted the crystalline structure. Moisture in the flue gas would be the case for all fuel applications, especially when firing natural gas.

One implication of Hitachi's findings is that gas firing (had it been available at PREPA Cambalache) could have caused even faster deterioration of the zeolite catalyst than observed. Therefore the past problems with hot SCR and fuel oil firing are more likely related to the catalyst formulation than to the use of fuel oil.

One possible strategy is to cool the exhaust gas to match the peak activity point of the less expensive medium temperature V catalyst at about 700 °F. This can be done using tempering air supplied from a cooling air skid. This options allows use of more familiar catalyst formulations without ammonia oxidation.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available as evidenced by both hot and conventional installations at coal-fired plants. Such improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR (low temperature) catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Fortunately sulfur is not a problem for the catalyst in high temperature and relatively low sulfur fuel applications (natural gas or distillate fuel oil) because the ammonium sulfate, bisulfate, sulfite deposits burn off at the high operating temperatures.

There are several examples of <u>conventional</u> SCR systems operating in Florida including:

- Kissimmee Utilities Authority Unit 3. 3.5 ppmvd NO_X on gas and 12 ppmvd on fuel oil.
- Progress Energy Hines Block 2. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- JEA Brandy Branch. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- TECO Bayside – seven combustion turbines. 3.5 ppmvd on gas.
- FP&L Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FP&L Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

There are several other approved projects now under construction in Florida that require <u>conventional</u> SCR systems. Most recently, DEP issued a permit for Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil.

SCR has been installed in several dozen simple cycle gas-fired LM6000 combustion turbines and in a few fuel oil-fired units. Typical emissions limits are on the order of 2.5 to 5 ppmvd. SCR was also specified for the recently approved LM6000 PC SPRINT units to be installed at the City of Tallahassee Hopkins Plant. The guaranteed NO_X limits are 5 ppmvd whether burning gas or fuel oil.

SCONO$_X$^{TM}

This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power is the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG but in the exhaust of an LM6000 PC SPRINT combustion turbine.

SCONO$_X$^{TM} systems were installed at seven sites ranging in capacity from 5 to 43 MW.[13] None were installed at large facilities.

SCONO$_X$^{TM} technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx^{TM} has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx^{TM} systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO$_X$^{TM} can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from a natural gas reforming unit.

The need for more cooling air (compared to SCR catalysts) to achieve the necessary temperature operating range and the requirement for natural gas or hydrogen for regeneration of the catalyst makes SCONO$_X$^{TM} infeasible for this project.

<u>4.2.3 Applicant's Original NO_X BACT Proposal</u>

The applicant originally proposed a BACT NO_X limit of 42 ppmvd @15% O_2 while operating 7000 hours per year and limiting annual fuel use to the equivalent of 4,420 hours per year. KEYS proposes to meet the proposed BACT emission limit by water injection.

The reader is referred to the KEYS application on-file with the Department and available on-line at the site given at the end of this review. In summary, the KEYS asserts that SCR is not technically or economically feasible for the following (paraphrased) reasons:

- SCR catalyst failed on an oil-fired simple cycle application at the PREPA project.
- There are insufficient hours of operation at other existing installations to conclude that SCR is reliable on oil-fired simple cycle units.
- The catalyst will have to be replaced every year.
- Any downtime is virtually unacceptable.
- The area is basically isolated and there are few power alternatives for the area especially if storms make power unavailable from the mainland.
- The marine environment and remote location drive up materials and construction costs.
- The overall cost per ton of NO_X removed is too high.
- The cost analysis submitted by the City of Tallahassee (who proposed SCR) contains errors.

4.2.4 Department's Draft NO_X BACT Determinations

A) Recent Test Data

Table 2 contains some information from a recent report prepared by the California Air Resources Board (CARB) to the Legislature regarding control technologies that reduce NOx emissions from gas-fired power plants.[14] All of the results appear to be on gas-fired LM 6000 combustion turbines. In all reported tests, NO_X emissions were less than 5 ppmvd. All but a few ammonia measurements were equally low. The one result listed in Table 3 for the New York Port Authority (NYPA) Hellgate plant is probably representative of the 11 new LM 6000 SPRINT combustion turbines known to be operated by the NYPA. According to a report prepared in 2003 for the NYPA, all of their units had no problems complying with the very strict NO_X limit of 2.5 ppmvd @15% O_2 during steady-state conditions.[15] However, during startup and shutdown these units often exceeded permit limits. This issue has since been resolved through a Consent Order and new permit limits for startup and shutdown periods.

Table 2. Test Results for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Date	NO_X / NH_3 (ppmvd @ 15% O_2)	Comments
NYPA, Hellgate, NY	2001	1.7 – 2.2 / 3.4 - 14	Water Injection & SCR
Calpine Lambie, CA	1/2003	2.5 / 1.5	Water Injection & SCR
Calpine Creed, CA	1/2003	1.5 / 0.8	Water Injection & SCR
Calpine Goose, CA	1/2003	2.4 / 0.4	Water Injection & SCR
N. Cal., Lodi, CA	7/2000	2.8 / 25	Steam Injection & SCR
Wellhead, Huron, CA	3/20/2002	2.7 / 0.4	Water Injection & SCR
Gilroy Energy, CA	2002	3.3 – 3.6 / 0.9 – 1.5	Water or DLE & SCR
Palm Springs, CA	2001	3.8 – 4.5 / 2.2 – 4.2	Steam or Water & SCR
San Diego, CA	2001/02	3.4 – 4.6 / 1.3 - 37	Water Injection & SCR

B) Recent Determinations

Table 3 includes some recent BACT determinations in Florida and other states for LM6000 series combustion turbines as well as some Lowest Achievable Emission Rate determinations. All specify SCR. Some of the information is from the previously mentioned CARB report to the Legislature.

All of the listed determinations are for NO_X emission limits less than or equal to 5 ppmvd @15% O_2. Most are approximately 2.5 ppmvd @15% O_2. In 1999, CARB issued guidance establishing a maximum value of 5 ppmvd for Power Plant Siting and BACT in California for simple cycle units.[16].

Additional information was located in the report prepared in 2003 for the New York Port Authority (NYPA) mentioned above. The purpose of the report was to review the performance of the numerous LM6000 PC SPRINT installations recently installed by NYPA. The permitted limits were issued at a time when there was much less information about actual performance of these units than there is today.

Based on the list, the "Top" technology in a "Top/Down" determination is 2.0 ppmvd for natural gas fired units and approximately 5.0 ppmvd for fuel oil-fired units. The NO_X BACT limit proposal submitted by KEYS is significantly greater than the top technology. It cannot be accepted without showing that technical or economic considerations make significantly lower values infeasible.

Table 3. Recent NO_X Standards for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2 and Fuel	Comments
Tallahassee, FL	100	5 – NG/fuel oil (24-hr)	2xLM 6000 PC SPRINT (NH_3=10)
W. Springfield, MA	84	3.5 /6.0 – NG/Oil (1-hr)	2x42 MW LM6000 (NH_3 = 7.0/10)
Lowell, MA	96	2.0 – NG (1-hr)	2x48 MW LM6000 (NH_3 =2.0)
Wallingford, CT	225	2.5 – NG (1-hr)	5x45 MW LM6000 (NH_3 = 6.0)
Shoreham, L. Island	~95	9 – fuel oil (1-hr)	2xLM 6000 (NH_3 = 10)
NYPA Hellgate	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Harlem River	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA N. 1st St.	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
NYPA 23rd St/3rd Ave	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Vernon Blvd.	94	2.5 – NG (1-hr)	2x47 MW LM6000 SPRINT CTs
NYPA Pouch Term.	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
NYPA Brentwood	47	2.5 – NG (1-hr)	1x47 MW LM6000 SPRINT CTs
Calpine Lambie, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT
Calpine Creed, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT
Calpine Goose, CA	50	2.5 – NG (3-hr)	1x49.9 MW LM6000 PC SPRINT

Table 3 (Cont.) Recent NO_X Standards for LM 6000 Simple Cycle Combustion Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2 and Fuel	Comments
Modesto Ripon, CA	95	2.5 – NG (3-hr)	2x47.5 MW LM6000 PC SPRINT
Lodi Energy, CA	50	3.0 – NG (3-hr)	1x49.6 MW LM6000 PC SPRINT
Herndon, CA	50	3.0 – NG (3-hr)	1x49.6 MW LM6000 PC SPRINT
N. Cal., Lodi, CA	49	3.0 – NG (3-hr)	1x49 MW LM6000 PC SPRINT
Wellhead, Huron, CA	45	3.5 – NG (3-hr)	1x45.4 MW LM6000 CTs
E.I. Colton, CA	48	3.5 – NG (3-hr)	1x48 MW LM6000 SPRINT
Gilroy Energy, CA	135	5 – NG (1-hr)	3x45 MW LM6000 PC
Palm Springs, CA	135	5 – NG (3-hr)	3x45 MW LM6000 SPRINT
Carson Energy, CA	42	5 – NG (3-hr)	1x42 MW LM6000 (started 1995)

It is noted that most if not all of the units listed in Tables 2 and 3 employ water or steam injection instead of DLE in conjunction with SCR. This means that gas-fired units are similar to the fuel oil-fired LM 6000 combustion turbines in regard to the employment of wet injection techniques and the purpose of SCR for further control.

i) Results for Shoreham Oil Fired LM 6000 Units

Long Island Power Authority (LIPA) supplies the fuel for, and Pennsylvania Power & Light (PPL) operates, the Shoreham Plant on Long Island, New York. The plant is one of several small installations sited at key locations throughout Long Island to meet escalating demand. There are two fuel oil-fired LM6000 combustion turbines at the Shoreham Plant.

For reference, Long Island is also characterized by a marine environment. The weather can be very cold and severe in the winter requiring heating of fuel or measures to insure the temperature of SCR catalyst is maintained at an optimal value.

The permit issued for the Shoreham Plant is a non-PSD permit with a short-term NO_X limit of 9 ppmvd @15% O_2 on a 1-hour basis and an annual limit of 22.5 tons between the two units. There is an NH_3 limit of 10 ppmvd @15% O_2 on a 1-hour basis. The permit requires both NO_X and NH_3 continuous emission monitoring systems (CEMS). NO_X emissions are controlled by water injection and SCR. Each unit has a 110-foot stack. The units started up in June 2002.

The Department downloaded 2003 CEMS NO_X data submitted by PPL from the EPA Air Markets Website. They operate in intermittent duty and never operate an entire 24-hour period in a day.

Figure 9 is the time series for August 2003 for both units. It includes all valid hours during which at least 0.25 hours of data were recorded. For the most part, emissions were in the range of 3 to 8 ppmvd @15% O_2. The peak value observed was 23 ppmvd and occurred during an hour that included a startup and only 0.32 hours of operation. Only 7.5 pounds of NO_X were emitted that entire hour.

According to PPL's filings with the Securities and Exchange Commission, the SCR system was provided by Deltak, L.L.C. The Department does not have information regarding the catalyst supplier used by Deltak.

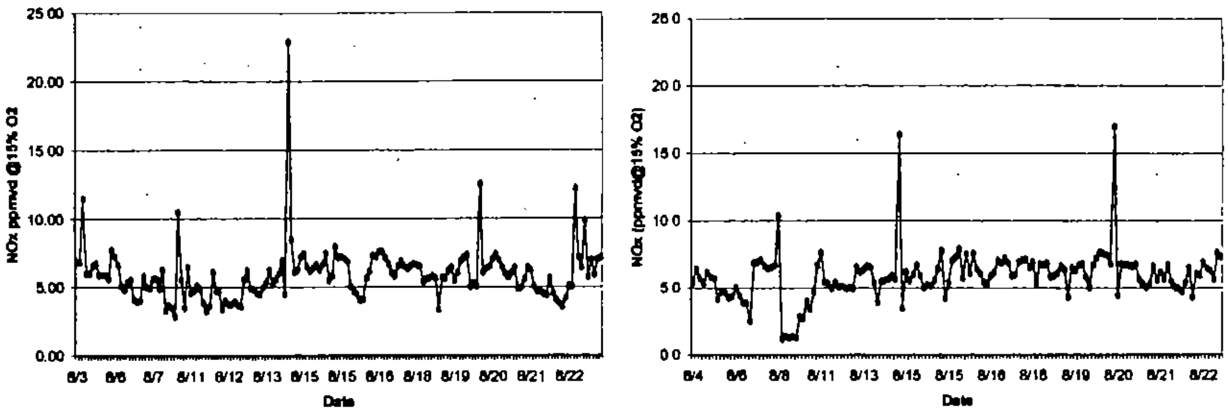

Figure 9 – NO_X Emissions - PPL Shoreham LM6000 Oil-Fired CTG-1&2 (August 2003)

ii) West Springfield Gas and Oil-Fired Project

The Consolidated Edison West Springfield Redevelopment Project is located in Massachusetts. It consists of two 42 MW GE LM6000 combustion turbines with water injection and SCR for NO_X control. Initially the project was permitted to fire natural gas only.

The initial BACT NO_X limit for the West Springfield Project (final approval June 9, 2003) was 2.5 ppmvd @15% O_2 and ammonia slip of 2.5 ppmvd NH_3 @15% O_2. The new units were initially not able to achieve the specified BACT limits during transient or steady-state conditions. Since that time, a new limit of 3.5 ppmvd @15% O_2 while burning gas has been set.

Massachusetts DEP approved use of ultralow sulfur fuel oil (< 0.0030 % sulfur) in November 2003 and allowed an increase in use of gas and fuel oil in July 2004.

Table 4 is a listing of the permit conditions applicable to the West Springfield Project. Table 5 summarizes the fuel use limitations for the two units.[17] Table 6 is a summary of operating hours and NO_X emissions since the units started operation in 2002 until the end of the third quarter of 2004. The information was accessed from the EPA Air Markets Website. The total NO_X emissions are 20.5 tons combined for the two units since they started up in 2002.

Table 4. Emissions Limits for two LM6000 Combustion Turbines at W. Springfield

Pollutant	Natural Gas		Oil (Ultra Low Sulfur)		Mass Emission Limits
	ppmvd @15% O_2	lb/hr (each CTG)	ppmvd @15% O_2	lb/hr (each CTG)	tpy (3) (both CTGs combined)
PM(2)	n/a	4.5	n/a	11.3	14.7
SO_2(4)	0.4	0.9	0.7	1.5	2.9
NO_X	3.5	5.9	6.0	10.8	19.3
CO	5.0(5) / 10.0(6)	4.3	5.0(5) / 10.0(6)	1.0	27.7
VOC	2.0	1.1	12.0	6.4	7.4
SAM	n/a	0.15	n/a	0.2	0.3
NH_3	7.0	4.4	10	6.2	10.6 (7)
Opacity	≤ 5 percent(8)		≤ 20percent(8)		

Table 5. Fuel Use Limits for two LM6000 Combustion Turbines at W. Springfield

Combustion Units	Natural Gas		Oil (Ultra Low Sulfur)	
	cubic feet/mon (1)	cubic feet/yr (2)	gallons/mon (1)	gallons/year (2)
CT-1 & CT-2	344,174,400	3,019,640,000	2,455,731 (3)	5,828,607 (3)

(1) Calendar Month
(2) Based on a rolling 12-month total
(3) Assuming natural gas heating value of 1000 Btu/ft^3 and oil heating value of 140,000 Btu/gallon.
(3) For every gallon of oil fired, the natural gas allowance (per calendar month or per rolling 12-month total) shall be reduced by 359.4 cubic feet.

Table 6. Hours and NO_X Emissions from W. Springfield LM6000 CTs (2002-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
CTG1/2004	291	87540	0.09	1.70
CTG2/2004	209	64180	0.11	1.40
CTG1/2003	674	211206	0.04	1.90
CTG2/2003	388	112371	0.11	1.90
CTG1/2002	652	228565	0.06	7.10
CTG2/2002	747	252897	0.05	6.50
Total/2002-04	**2961**	**956759**	**0.04**	**20.50**

Figure 10 is a time series for the dual fuel fired units, Units 1and 2, at West Springfield. The graph includes only the hours during which fuel oil was fired in 2004. Substantial firing after mid-year was primarily with natural gas due to the higher seasonal cost of fuel oil. The graphed values represent only discrete hours that are not necessarily contiguous. They do not include data when the unit operated for 15 minutes or less. This avoided inclusion of excluded data as "zeros". The high values in January apparently occurred during hours that contained both a startup and a shutdowns. The others occurred at very low load (< 8 MW). Although the concentrations appear to be high, the impact on annual emissions is minimal.

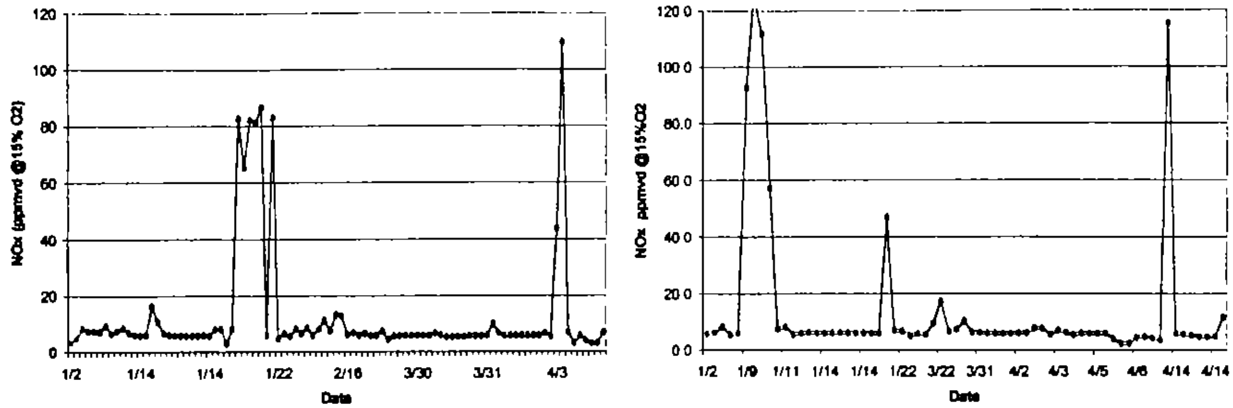

Figure 10 – NO_X Emissions - W. Springfield LM6000 Dual Fuel Units 1&2 (Oil, 2004)

The SCR systems were provided by Peerless and used Haldor Topsoe catalyst. The precise catalyst formulation is not yet known by the Department. It is certainly not zeolite and is believed to be a titanium and tungsten formulation. A Department representative visited with representatives of Haldor Topsoe at the 2004 Power Gen Conference.[18] They showed the Department representative startup curves for one of the West Springfield combustion turbines while firing oil. According to the curves, startup was accomplished within 10 minutes after which NO_X emissions were less than 5 ppmvd and at times approached 2 ppmvd @15% O_2.

Department personnel contacted the Massachusetts DEP. Their representatives stated that the West Springfield Project has not had any problems meeting the new limits of 6 ppmvd while burning natural gas and 10 ppmvd @15% O_2 while burning fuel oil.[19] The Department also contacted a representative of Consolidated Edison who said they have had no problems so far and there has been no sign of catalyst degradation.[20]

iii) FPL Bayswater - Pratt& Whitney Oil and Gas Fired Projects

Bayswater consists of two projects built by FPL in the area of Far Rockaway, Queens, New York. It is adjacent to the existing Keyspan Generating Facility. The first of the two FPL projects was called Bayswater and the second was called Jamaica Bay. They are treated as a single facility called Bayswater under the EPA Acid Rain Program. Following is a picture of the two FPL projects and the separate Keyspan facility.

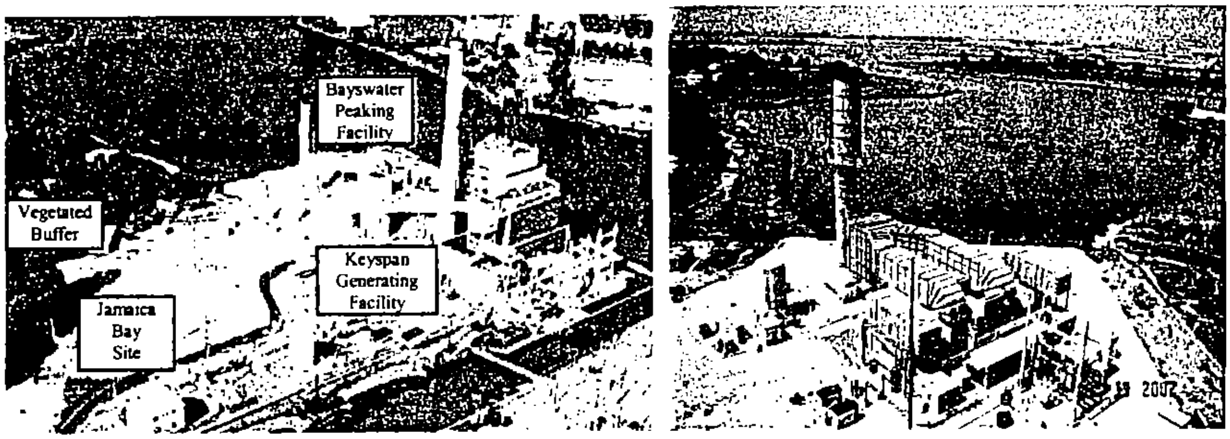

Figure 11 – FPL Bayswater Projects. Two Dual Fuel Pratt & Whitney Swift-Pac Sets

The Bayswater facility is comprised of two simple cycle dual fuel 54 MW Pratt & Whitney FT-8 Swift-Pacs. Each Swift-Pac consists of two small combustion turbines, "pantleg" ducting, a single electrical generator and stack. The primary fuel for the Bayswater Project is natural gas. The primary fuel for the Jamaica Bay project is fuel oil.

According to the Project Environmental Assessment, the NO_X emission limits proposed for the Jamaica Bay project (the second of the two) were 2.5 ppmvd and 6.0 ppmvd @15% O_2 for gas and oil respectively.[21] The annual emissions through the third quarter of 2004 for both projects are listed in the following table. The information source is the EPA Markets Website.

Table 7. Hours and NO_X Emissions from FPL Bayswater P&W CTs (2002-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
Bayswater/2004	1,567	889,976	0.02	7.2
Jamaica Bay/2004	343	177,743	0.05	2.4
Bayswater/2004	1,210	675,991	0.05	14.5
Jamaica Bay/2003	517	286,020	0.07	7.1
Bayswater/2002	708	377,376	0.07	12.8
Total/2002-04	**4345**	**2,407,106**	**0.037**	**44.0**

Figure 12 is a time series for August 2004 for the two Bayswater units (i.e. Bayswater and Jamaica Bay). The graphed values represent all hours for which data were reported including startups and shutdowns. All high values occurred during partial hours of operations were related to startup. For the most part emissions were typically 5 ppmvd for the fuel oil-fired Jamaica Bay Unit (graph on left) and 2 ppmvd for the Bayswater Unit during steady state.

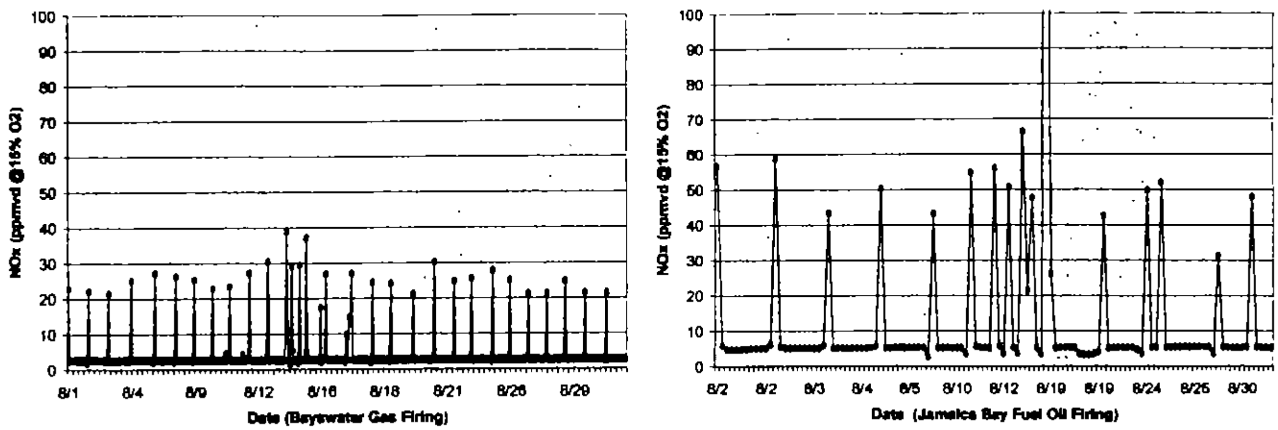

Figure 12 – NO_X Emissions from FPL Bayswater Gas and Oil-Fired Units (August, 2004)

The two plots are similar in that each indicates higher emissions during startup, representative of the water injection targets of 42 ppmvd for oil firing and 25 ppmvd for gas firing prior to enabling of the SCR systems. Although the concentrations are relatively high during each startup hour (usually a fraction of an hour), mass emissions are actually low.

Department personnel contacted a representative of Envirokinetics who supplied the SCR systems for both projects.[22] The gas-fired Bayswater project that started up in 2002 used a catalyst formulation known as Engelhard VNX-HT. According to Engelhard, it is designed for a temperature range of 600 to 875 °F with an optimum range between 800 and 850 °F. The catalyst has a relatively low vanadium (V) content and high titanium oxide (TiO_2). This is consistent with the nominal 840 °F exhaust temperature of the P&W Swift-Pac characteristics.

The fuel oil-fired Jamaica Bay project that started up in 2003 used a catalyst formulation known as Haldor-Topsoe DNX. Topsoe's formulations are typically tungsten (W) and TiO_2. This is consistent with the previous discussion regarding the Hitachi catalyst and operation at moderate to high temperature.

Both catalysts perform well based on the graphs shown above. In its research, the Department also found that the Haldor-Topsoe product has lower pressure drop characteristics, which means less power is lost.[23]

Department representatives contacted an operations expert of FPL Energy at the Bayswaters facility. He confirmed the details provided by Envirokinetics and Haldor-Topsoe. Among the key points were that the units are 98-99% reliable. Both comply with their respective NO_X emission standards.

The only concern expressed by the FPL representative about the use of SCR with fuel oil is an effect on the continuous emission monitoring system (CEMS) for ammonia. Apparently, small amounts of carbon build up in the sampling system. It is theorized that the carbon buildup causes adsorption of ammonia which can be subsequently released. The observation is that NH_3 levels appear to oscillate. No effect is seen on NO_X removal or the functioning of the catalyst. FPL is experimenting with changes to the NH_3 sampling system.

The Department concludes that this side-by-side comparison constitutes a good real-world experimental comparison of SCR for simple cycle gas firing with SCR for fuel oil-firing. Most factors other than the fuels and their delivery systems are equal. The results suggest that problems at previous simple cycle installations had less to do with inherent characteristics of fuel oil than they have to do with catalyst formulation.

iv) Hawkeye Greenport Long Island Oil-fired Project and Freeport Energy Gas-fired Project

In additional information submitted by KEYS, reference was made to "the failure of the catalyst at the Greenport Facility" on the far east side of Long Island. The Hawkeye (formerly Global) Greenport facility is a fuel oil-fired 50 MW P&W Swift-Pac Combustion Turbine set. The unit started up in 2003.

By its letter dated February 16, 2005 KEYS referred the Department to Mr. Tom Turner, President of Turner Envirologic, and the supplier of the SCR system installed at Hawkeye. Department representatives contacted Mr. Turner. He described the original catalyst as a zeolite formulation consistent with the failed product at the oil-fired PREPA simple cycle project. The zeolite catalyst at Hawkeye was replaced with a TiO_2 and W formulation consistent with the successful product at the FPL Bayswater units.

Mr. Turner added that his firm also supplied the SCR system on the 50 MW Freeport Energy facility that consists of a gas-fired GE LM6000 SPRINT combustion turbine. The same zeolite catalyst formulation was also replaced with the TiO_2 and W formulation previously described. His firm also oversaw the replacement of the catalyst at the gas-fired LM6000 for the City of Burbank with the Haldor-Topsoe formulation. He also supplied the SCR system for the 100 MW dual-fuel Larkspur, San Diego project that incorporates LM 6000 combustion turbines.

The following table is a summary of the operation of the Hawkeye Greenport oil-fired unit since its startup. The total annual and average NO_X emissions that include startups are low.

Table 8. Hours and NO_X Emissions from Hawkeye Greenport P&W CT (2003-2004)

Unit/year	Hours	Heat Input	NO_X (lb/mmBtu)	NO_X (TPY)
Hawkeye (Oil)/2004	699	333,809	0.04	4.3
Hawkeye (Oil)/2003	773	363,120	0.05	4.5
Total/2003-04	**1,472**	**696,929**	**0.026**	**8.9**

The lb/mmBtu entries for 2003 and 2004 based on the average of the individual hourly measurements. However the lb/mmBtu entry for the totals is less because the data are weighted by production. Basically the higher 2003 and 2004 values include partial hours such as startups that are characterized by greater lb/mmBtu (and ppmvd) values but lower lb/hr values. The time series for emissions from the Hawkeye Greenport oil-fired facility during August 2003 and August 2004 are displayed are displayed in Figure 13.

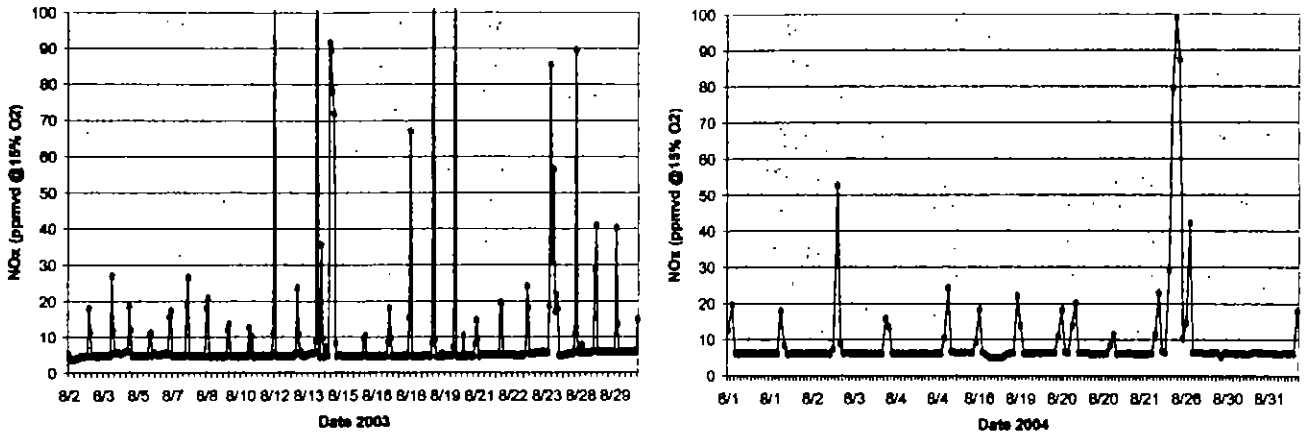

Figure 13 – NO_X Emissions - Hawkeye Greenport Oil-fired Units (Aug., 2003, 2004)

The difference between the two graphs is that startup emissions tended to be greater in 2003 than 2004. While the Department does not have the details regarding the alleged failure, it appears that steady-state emissions have been low. It is possible that the problems were related to very restrictive startup emission limits or problems maintaining low ammonia emissions.

As mentioned, Mr. Turner said that the Freeport gas-fired experienced similar problems. There are two LM6000 SPRINT units located at the site. One is owned by Freeport Energy. The other is owned by a merchant company affiliated with PPL. Following is the time series for the unit designated as Freeport for most recent months given in the EPA Air Markets Website.

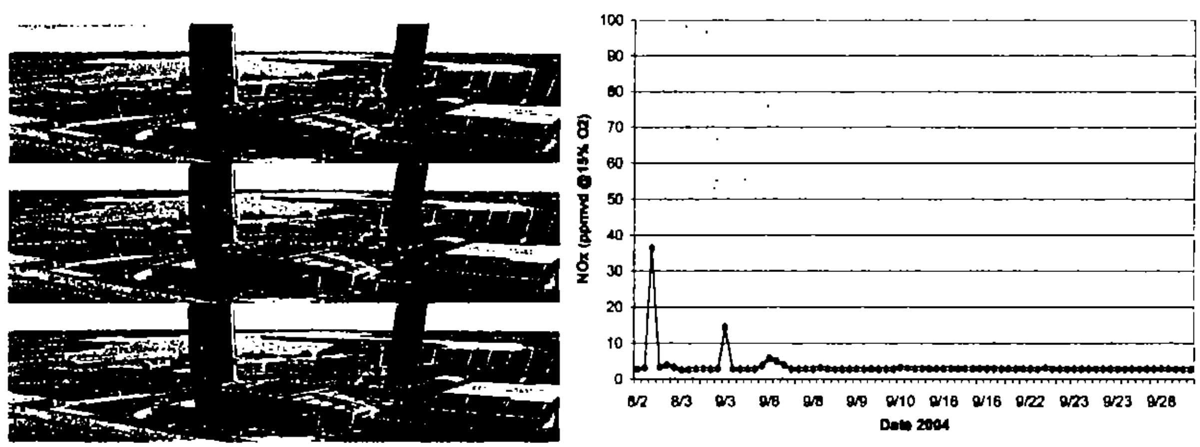

Figure 13 – Photo and NO_X Emissions – Freeport Energy Gas-fired Unit (Aug/Sept., 2004)

Emissions from the Freeport gas-fired LM6000 unit are clearly very low and meet the 2.5 ppmvd limits except during startup. In any case, the compelling facts are: both the fuel oil-fired and gas-fired unit referenced by Mr. Turner operate well now. The zeolite catalyst in each has been replaced with a formulation more appropriate for the application. The source, Mr. Turner, cited by KEYS does not believe fuel oil-firing was the cause of the alleged failures. In fact, he stated that the cause of the alleged failures was related to the zeolite catalyst for the particular conditions.

Mr. Turner's statements and the Department's conclusions are consistent with the observations by Hitachi about zeolite catalyst, the PREPA failure using zeolite catalyst, and the FPL Bayswater success using the Cormetech low V/TiO_2 and the Haldor-Topsoe TiO2/W formulations. This is not to suggest that zeolite catalysts are doomed to failure. They just need to be reformulated or cooled or used within the correct applications.

v) City of Tallahassee Fuel Oil and Gas-fired Project

The Department recently determined that SCR is cost-effective for a project by the City of Tallahassee (COT) to install two GE LM6000 PC SPRINT gas and fuel oil-fired combustion turbines. The project was permitted to operate 4,000 hours per year while firing fuel oil and 1,600 hours per year while firing natural gas. The BACT emission limit was determined to be 5 ppmvd @15% O_2 whether gas or fuel oil is used.

KEYS reviewed the application and determination for the COT project and claim numerous errors and flaws. The Department notes that the calculations submitted by COT actually represent "marginal" rather than average cost-effectiveness.

The higher marginal cost-effectiveness values (adding SCR to wet injection) would not change the conclusion. Conducting the analysis assuming baseline control to the NSPS value of approximately 110 ppmvd would also be cost-effective.

C. Cost-effectiveness of NO_X Control

Cost-effective values for the KEYS project were originally submitted in a response to a request by the Department for additional information and with the intent of the unit to be operated almost continually for a total of 4,420 fuel equivalent hours. The Department is in disagreement with KEYS with respect to several items included in this original analysis. The following summarizes the major issues of which the Department is in disagreement.

The Department believes that the KEYS total direct costs estimate (weighted from several bids) is somewhat high because of a bid by GE Energy. The GE bid is likely high due to the fact that this company would have used one of the other suppliers, added an additional charge, and not actually supply the same duration guarantee as the underlying bidders.

Cost-effective values supplied by KEYS are also high because of the inclusion of a 20 percent ($626,000) contingency. EPA believes the contingency should be 3%. In any event, since KEYS has decided to use GE as the overall project supplier, the contingency for the SCR system will be absorbed into the total LM6000 project contingency that is surely less than 20%.

The cost of an annual catalyst change ($383,000) is unreasonable because the bidders will guarantee the catalyst lifetime or pay a pro-rated replacement cost. The annual replacement assumption alone adds about $2,000 of cost per ton of NO_X removed.

The claimed cost ($353,000) of power lost during an annual catalyst change-out is also unreasonable. EPA excluded this term in its own review. Even if such costs were allowed, correction for a change-out every three years would lower the cost-effectiveness value by nearly another $2,000 per ton. Additionally, the Department believes that the change would not take one week, but rather 2 to 4 days. Most likely such a change out can be timed to other scheduled outage that occur in terms of several years rather than every year.

An interest rate of 7% is assumed. While EPA uses the concept of the "social" interest rate, it is not a practical term. The actual interest rate for a non-taxable utility for bonds maturing over a period of 15 years is lower. However at this time, the difference between the social interest rate and the real interest rate for FMPA is not great. It is noted that claims to use social interest rates can establish a precedent that makes it difficult to use the real interest rates on subsequent projects when the rates increase.

Rather than point out other differences in opinion, it is sufficient to state that with a few corrections, the *marginal* cost of NO_X control is cost-effective for the original intended operation of 4.420 equivalent hours of operation. For example, EPA Region 4 estimated the cost-effectiveness at $6,120 which would be cost-effective whether it is on a marginal or an average basis. The *average* cost, had it been provided by KEYS and reviewed by the Department and EPA, would easily be cost-effective.

Table 9 is an updated cost-effectiveness analysis submitted by KEYS. It includes estimates of *average* cost-effectiveness for NO_X control by water injection and by a combination of water injection and SCR. It also includes an estimate of the *marginal* cost-effectiveness between the two strategies. The analyses were based on their revised request of 2,500 hours of operation per year instead of continuous operation and the "fuel equivalent" of 4,420 hours per year of operation.

As stated earlier, the Department is in disagreement with several key points regarding the cost effectiveness estimates supplied by the applicant. The analysis presented in Table 9, although revised to reflect the newly requested 2,500 operating hours, remains unchanged in regard to the Department's concerns. Though these estimates are believed to be relatively high, the data is useful in demonstrating some important concepts.

The vast disparity between marginal vs average costs should be noted. Clearly even with operation limited to 2,500 hours, SCR is cost effective from an *average* standpoint. Based on the KEYS estimate however, from a *marginal* standpoint, SCR appears to be less cost effective.

It should also be noted that the cost effectiveness presented in this table was based on a reduction from approximately 87 tons per year to 10 TPY. In actuality, prior to reaching 2,500 operating hours, the unit will be producing 60 TPY or less, thus making the reduction even less cost effective ($22,000/ton). Compound this with the fact that once SCR is in place, the unit need only remain under 40 TPY to avoid PSD applicability. In this case, the cost effectiveness from a *marginal* standpoint of the reduction from 60 to 40 TPY begins to reach extreme proportions ($54,000/ton). These estimates are based on projected fuel usage and equivalent operating hours supplied by KEYS and presented in Table 10.

Other circumstances unique to this project that have been considered by the Department include the following:

- The KEYS project is unique in that it is located on an island, virtually isolated from the mainland, but for a single highway. This isolation adds to the cost and reliability of delivery of goods.
- In the event of a major hurricane strike, Keys residents most likely must rely on locally supplied power. The addition of this unit to the existing facility will ensure the needs of the residents will be met during such an emergency.
- The total project size is very small. It consists of only one 48 MW unit that will operate on a limited basis for at least the first few years following startup. According to projected fuel usage and equivalent operating hours submitted by KEYS, this unit is expected to operate for less than 2,000 equivalent full load hours during the first 4 years of operation.

The Department has concluded that based on marginal and average analysis, SCR is cost effective once 2,500 hours of operation has been reached and likely prior to that. However, taking into consideration the unique circumstances associated with this project, the Department will allow the applicant to defer the installation of SCR until the unit reaches 2,500 hours of annual operation, when it is obviously cost effective from both a marginal and an average standpoint.

Table 9. Average and Marginal Cost-Effectiveness for NO_X Control Options

	WI Alone Average C.E.	WI + Plus SCR Average C.E.	WI + SCR vs WI Marginal C.E.
	Dollars	Dollars	Dollars
Total Direct Cost (DC)	**$477,018**	**$3,606,018**	**$3,129,000**
Indirect Capital Cost			
Contingency	$95,000	$721,000	$626,000
Engineering & Supervision	$48,000	$361,000	$313,000
Construction & Field Exp.	$24,000	$180,000	$156,000
Construction Fee	$48,000	$361,000	$313,000
Startup Assistance	$10,000	$73,000	$63,000
Performance Test	$5,000	$36,000	$31,000
Total Indirect Cap. Cost	**$230,000**	**$1,732,000**	**$1,502,000**
Installed Costs	**707,018**	**5,338,018**	**4,631,000**
-SCR Catalyst Cost		-$317,000	-$317,000
Total Capital Investment (TCI)	**$707,018**	**$5,021,018**	**$4,314,000**
Direct Annual Costs	Dollars	Dollars	Dollars
Catalyst Replacement		$145,182	$145,182
Operating & Maintenance	$13,000	$83,000	$70,000
Water Usage	$184,500	$184,500	
Reagent Feed (Ammonia/Water)		$27,985	$27,985
Power Consumption	$3,703	$24,056	$20,353
Lost Power Generation			
Water Injection Equipment	$-592,500	$-592,500	
Backpressure		$63,320	$63,320
Catalyst Replacement		$48,661	$48,661
Increased Fuel Consumption	$136,649	$136,649	
Annual Distribution Check		$55,000	55,000
Total Direct Annual Costs	**$-254,648**	**$175,852**	**$430,501**
Indirect Annual Costs			
Overhead	$7,800	$49,800	$42,000
Administrative Charges	$14,140	$107,140	$93,000
Property Taxes			
Insurance	$7,070	$53,070	$46,000
Capital Recovery	$77,560	$551,560	$474,000
Total Indirect Annual Costs	**$106,570**	**$761,570**	**$655,000**
Total Annualized Costs	**$-148,078**	**$937,423**	**$1,085,501**
Annual Tons NOx Produced	**87.1**	**87.1**	**87.1**
Annual Tons NOx Not Produced or Removed	**533.1**	**609.8**	**76.8**
Annual Tons NOx Emitted	**87.1**	**10.4**	**10.4**
Cost Effectiveness ($/ton)	**$-278**	**$1,537**	**$14,134**

Table 10. Projected Fuel Usage and Equivalent Operating Hours

Year	Hours of Operation	Gallons Fuel Burned	Equivalent Full Load Hours	NOx Produced in Tons
2006	1,905	3,740,000	1,219	42.5
2007	2,259	4,436,000	1,446	50.4
2008	2,648	5,200,000	1,988	59.1
2009	3,107	6,100,000	2,282	69.3
2010	3,565	7,000,000	2,542	79.5
2011	3,972	7,800,000	2,770	88.6
2012	4,329	8,500,000	2,999	96.5
2013	4,685	9,200,000	3,295	104.5
2014	5,149	10,110,000	3,651	114.8

D. NO_X BACT Emission Limits

The Department will set a NO_X limit of 42 ppmvd @15% O_2 while firing oil and 15 ppmvd @ 15% O_2 while firing natural gas. Compliance with these limits must be demonstrated during an initial test and during annual tests thereafter. Compliance with the 15 ppm limit on gas will be required when natural gas becomes available to the Keys. These limits apply for the restricted operation of 2500 hours per year requested by the applicant.

If in the future there is a need to relax the requested restriction on hours, alternative limits would have to be met. The use of SCR and an emissions limit of 5.0 ppmvd value reflect BACT with operation greater than 2,500 hours. However a 9.0 ppmvd value based on the fuel use limitation requested in the original application would limit NO_x emissions to less than 40 tons per year. These limits for operation greater than 2,500 hours have been incorporated into the permit.

The Department would revise the higher long term limit downward in conjunction with any additional increases in fuel use. A continuous NO_x limit of 5 ppmvd @ 15% O_2 while firing fuel oil must be met at that time.

4.3 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

In the original application based on the use of 13,567,000 gallons per year (4,420 equivalent hours) of fuel oil No. 2, the potential of SO_2 and SAM emissions are reported as 47.8 TPY and 14.6 TPY respectively. This exceeds their significant emission rates of 40 TPY and 7 TPY requiring BACT determinations for both pollutants.

However, BACT determinations for SO_2 and SAM are not required based on the revised emission estimates (2,500 operating hours) submitted by KEYS. The revised potential emissions of SO_2 and SAM are 29.5 and 6.8 TPY respectively.

The applicant has indicated that if there is a future need to relax the requested restriction on hours (> 2,500), that they would take practicably enforceable limits of 39.9 TPY SO2 and 6.9 TPY SAM to avoid BACT determinations for these pollutants.

The following are the BACT analyses for SO_2 and SAM based on the use of 13,567,000 gallons per year (4,420 equivalent hours) of fuel oil No. 2 as presented in the original application.

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

The applicant referred to a table in a Department of Energy analysis of the cost impact of a regulation requiring a complete replacement of the standard specification (0.05% S) highway diesel fuel by 0.0015% sulfur diesel by 2011.

A portion of the table is reproduced below.

Table E1. End-Use Prices and Total Supplies of Highway Diesel, 1999 and 2007-2015, Assuming 5-Percent Return on Investment

Analysis Case	1999	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
End-Use Prices of Highway Diesel (1999 Cents per Gallon)									
Reference (500 ppm)	114.0	121.6	122.3	123.0	123.6	124.1	124.3	122.6	124.3
Regulation (ULSD)	NA	124.5	129.0	129.5	130.1	131.3	129.4	129.4	129.7
Higher Capital Cost (ULSD)	NA	129.1	129.9	130.5	131.2	132.[illegible]	130.1	130.3	130.5
2/3 Revamp (ULSD)	NA	128.9	129.2	129.[illegible]	130.7	131.7	129.7	129.7	130.0
10% Downgrade (ULSD)	NA	129.6	129.4	129.9	130.8	133.2	130.9	129.4	130.7
4% Efficiency Loss (ULSD)	NA	128.6	129.0	129.5	130.5	131.4	129.6	129.4	130.0
10% Energy Loss (ULSD)	NA	128.3	129.3	129.6	130.3	131.5	129.5	129.6	129.8
Severe (ULSD)	NA	130.4	130.7	131.4	132.2	134.3	131.1	131.2	131.7
No Imports (ULSD)	NA	130.2	130.4	130.8	131.6	132.3	130.5	130.3	[illegible]
Total Highway Diesel Supplied (Million Barrels per Day)									
Reference									
Total (500 ppm)	2.43	3.09	3.15	3.21	3.27	3.32	3.55	3.18	3.41
Regulation									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51
Higher Capital Cost									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51
2/3 Revamp									
500 ppm	2.43	0.70	0.71	0.72	0.26	0.00	0.00	0.60	0.00
ULSD	0.00	2.40	2.45	2.50	3.02	3.40	3.63	2.59	3.51
Total	2.43	3.10	3.16	3.22	3.28	3.40	3.63	3.19	3.51

According to the applicant:

> *"In the Regulation case, the marginal annual pump price for ULSD is projected to range from 6.5 to 7.2 cents per gallon between 2007 and 2011. The peak differential is projected to occur in 2011, when oil refiners must produce 100 percent ULSD."*

The applicant inferred from the table that difference shown between the Reference (0.05% S) case and the Regulation case (ULSD – 0.0015% S) represents market price differences. In fact, it actually represents the price differential of regulating diesel sulfur compared to what the price would have been in the absence of regulation.

For example, the table indicates a price difference of 7.2 cents per gallon in 2011. This is one of the values mentioned in the quoted excerpt from the application. It would be meaningless to discuss price differences in 2011 between available grades when the table specifically presumes no 0.05% sulfur fuel will be available.

EPA mandated the new grade of diesel because of the contribution of SO_2 to the formation of fine particulate matter in the environment as well as the possibility of poisoning catalysts used to control pollution from diesel engines. It is not unreasonable to require use of the superior grade as BACT in new exclusively diesel-fired sources of air pollution.

In the original application, KEYS estimates that maximum annual SO_2 emissions are 48 TPY based on use of 13,567,000 gallons of fuel oil No. 2 (4,420 equivalent hours). This assumes all sulfur is converted to SO_2. KEYS also assumes SAM emissions of 15 TPY. If the SAM emission estimate is correct, then SO_2 emissions will be equal to approximately 36 TPY which is less than the significant emission rate for SO_2.

Even if the KEYS SO2 emission estimates are correct, projections provided by KEYS indicate fuel oil use sufficient to cause 48 TPY of SO_2. Emissions will not actually reach that level until 2017. The fuel use corresponding to 40 TPY (the significant emission rate for SO_2) is 11,200,000 gallons. This level will not be reached until 2015.

It is doubtful that KEYS will ever emit more than 40 TPY based on:

- Correction of double-counting of sulfur as SO_2 and SAM
- Projected fuel use through 2015;
- Typical delivered sulfur content of low sulfur fuel oil (actually less than 0.05);
- Ultimate availability of ultralow sulfur at little or no premium.

The Department's BACT analyses for SO_2 and SAM control at operation beyond 2,500 hours indicate use of ultralow sulfur diesel fuel. However, KEYS has requested practicably enforceable limits of 39.9 tons of SO_2 and 6.9 tons of SAM per year to avoid BACT determinations and are proposing the use of 0.05 % sulfur fuel oil by weight. The SO_2 limit of 39.9 TPY will provide assurance, even assuming a worst case scenario of an SO_2 oxidation rate of 15% conversion of SO_2 to SO_3, and an assumed 100% conversion of SO_3 to H_2SO_4, that SAM emissions will remain below the significant level of 7.0 TPY.

Note: The Department can allow subtraction of the portion of sulfur that becomes SAM from the SO_2 calculation for the purposes of PSD applicability. This is irrespective of whether or not such a consideration is allowed for the purpose of determining use of SO_2 allowances under the Acid Rain Program.

4.4 Particulate Matter (PM/PM_{10}) BACT Determination

PM/PM_{10} Formation and Control Options

PM and PM_{10} are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Low sulfur distillate fuel oil will be the only fuel fired and is efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure.

Applicant's PM/PM_{10} Proposal

KEYS proposed a BACT emission limit of 25 lb/hr for PM and the same value for PM_{10}. The most recent determination (City of Tallahassee) by the Department for an LM6000 PC SPRINT while operating on fuel oil is 15 lb/hr for PM and the same value for PM_{10}. However, the compliance method is a visible emission standard of 10%.

Department's Draft PM/PM_{10} BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire distillate oil that contains no more than 0.05% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.

5. NEW SOURCE PERFORMANCE STANDARDS

5.1 Combustion Turbines

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NO_X (oil) $\leq$ 106 ppmvd @ 15% O_2 (corrected for a heat rate of 10.20 kJ/watt-hr assuming no fuel bound nitrogen; and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

A more recent standard was proposed by EPA on February 18, 2004. The proposed standard, 40 CFR60, Subpart KKKK would require adherence to the following limits:

- NO_X (oil) $\leq$ 1.2 lb/megawatt-hour. This is approximately equal to 35 ppmvd @15% O_2.
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.05% by weight.

The Department considers the draft BACT standards more stringent than the existing or the proposed NSPS standards. The GE LM6000 PC SPRINT will not meet the proposed NO_X standard without additional control such as proposed by the Department. The Department will request that EPA make a determination regarding KKKK applicability to the present project during the public comment period.

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

In the original application, the proposed project predicted increases in emissions of four pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, NO_X, SO_2, and SAM. In the revised application, the predicted increases in emissions of two pollutants are at levels in excess of PSD significant amounts: PM/PM_{10} and NO_X. The following analyses are based on the revised application. PM_{10} and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them.

6.2 Climate

The annual average high temperature for Key West is 83 degrees with their highest reported temperature being 98 degrees in 1997. The annual average low is 73 degrees. According to the National Weather Service in Key West, there is no known record of frost, ice, sleet, or snow in Key West. Prevailing easterly tradewinds and sea breezes suppress the usual summertime heating. Humidity remains relatively high during the entire year.

The wind rose below depicts the winds at Key West from 1987–1990, which are predominately from the east.

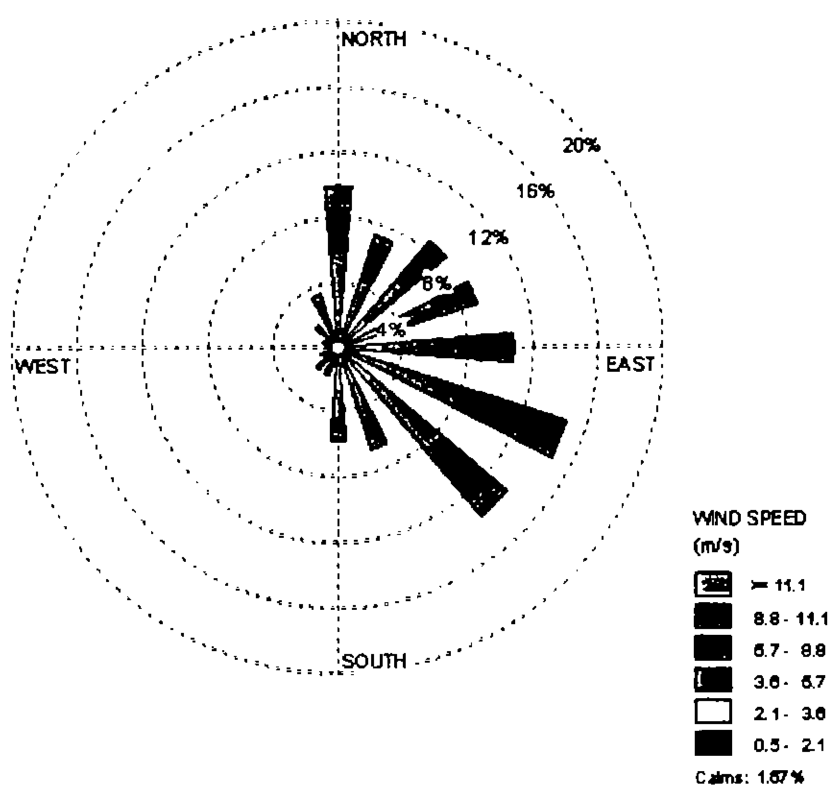

Figure 14 – Key West Wind Rose – 1987 to 1990

6.3 Major Stationary Sources in Monroe County

The current largest stationary sources of air pollution in Monroe County are listed below. The information is from annual operating reports submitted to the Department except as noted.

Table 11. Major Sources of NO_X in Monroe County (2003)

Owner	Site Name	Tons per year
KEYS Energy Services	Stock Island Power Plant (existing)	290**
KEYS Energy Services	***Stock Island Power Plant (proposed)***	***94.9***
City of Key West	Southernmost Waste to Energy Facility	83
KEYS Energy Services.	Cudjoe Key	63*
FL Keys Electric COOP Assoc.	FL Keys Electric COOP Assoc.	45

** Recently shut down*

***Potential to emit from Construction Permit*

Table 12. Major Sources of PM in Monroe County (2003)

Owner	Site Name	Tons per year
KEYS Energy Services	***Stock Island Power Plant (proposed)***	***31.3***
KEYS Energy Services	Stock Island Power Plant (existing)	37*
City of Key West	Southernmost Waste to Energy Facility	8
FL Keys Electric COOP Assoc.	FL Keys Electric COOP Assoc.	6

**Potential to emit from Construction Permit*

Emissions from the proposed project and the existing Stock Island Power Plant are the highest in the county. However, Monroe County does not have as many stationary sources as other Florida Counties and therefore, the conclusion that the emissions from Stock Island are high due to the information in the above tables cannot be made.

6.4 Air Quality and Monitoring in the Monroe County

Monroe County does not have an ambient air quality monitoring network. However, due to the location, climate, size and population of the county, it is assumed that air pollutant concentrations are less than other areas that have monitoring networks, such as Miami-Dade. The entire state of Florida is in attainment for all criteria pollutants.

6.5 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10} and NO_X. A significant impact analysis is performed on each of these pollutants to determine if a project can even cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class I Everglades National Park (ENP) and the PSD Class II Areas (everywhere except the ENP).

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, then additional modeling including emissions from all facilities or projects (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS or PSD increments.

The applicant's initial PM/PM_{10}, and NO_X air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except ENP). These values are tabulated in the table below and are compared with existing National Ambient Air Quality Standards.

Table 13. Maximum Projected Air Quality Impacts from Stock Island Unit 4 for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.1	1	50	NO
	24-Hour	4.9	5	150	NO
NO_2	Annual	0.2	1	100	NO

Maximum predicted impacts from the project are much less than the respective AAQS in the area. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Everglades National Park (ENP) located about 90 km to the northeast of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM_{10}, and NO_X air quality impact analyses for this project indicated that maximum predicted impacts are less than the applicable SILs for the Class I area. Therefore no further detailed modeling efforts are required.

Table 14. Maximum Air Quality Impacts from the Stock Island Unit 4 Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.0004	0.2	NO
	24-hour	0.02	0.3	NO
NO_2	Annual	0.0005	0.1	NO

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

Table 15. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels.

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4.9	10	NO
NO_2	Annual	0.2	14	NO

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project is the following:

- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition.

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from Key West and West Palm Beach respectively. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on

July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP. Meteorological MM4 and MM5 data used in this model was from 1990, 1992 and 1996.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources.

The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

6.6 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Very low emissions are expected from gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, and NO_X as a result of the proposed project, including background concentrations, will be considerably less than the respective AAQS.

Since the project impacts are less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife (including the Endangered Key Deer) will be minimal or insignificant.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. The CALPUFF model is also used in this analysis to produce quantitative impacts. The results of the analysis show that nitrogen and sulfur deposition rates are substantially lower than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

In addition, the National Park Service reviewed the proposal for CT Unit 4 at Stock Island and concluded that they "believe that there will not be any significant impacts on resources at the Everglades National Park."

Impact on Visibility:

The applicant submitted a visibility analysis for the Everglades National Park. The analysis included modeling from the CALPUFF model. The CALPUFF model predicted modeled impacts well below the 5% visibility impairment based on criteria from the NPS.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth near the project.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, the population of Key West and Monroe County has grown by an average of 2% per decade since 1980. The population of Monroe County is currently about 80,000. In 1980, it was 63,000. In 1990, Stock Island had a population of about 3,600. The county depends on tourism economically. In 2000, 30% of the population worked in the tourism industry. With tourism being the main economic support for the Keys, the area is not a major industrial center. The main non-tourist related "industry" in the Keys is the military presence in the area.

Since 1977, there have been several projects at Stock Island including construction of two 8.8 MW diesel engines in 1990-91. One 23.5 MW combustion turbine was moved from Key West to Stock Island in 1995-96. Two 20 MW combustion turbines were installed in 1998. The Ralph Garcia Steam Unit was permanently retired in the 1980's. For reference, that unit still holds 2571 SO_2 allowances under the Federal Acid Rain program.

Southernmost Resource Recovery Facility surrendered its Title V Operation Permit in 2004 and permanently shut down.

Mobile source fuel quality has improved since the 1970's. The related reduction in transportation-related NO_X, SO_2 and VOC emissions probably offset increases due to traffic growth. The transportation-related decreases and the retirement of the Ralph Garcia Steam Plant and Southernmost Resource Recovery Facility provide a basis for concluding that there has not been a deterioration of air quality in the lower Keys since 1977. The proposed project is not likely to change that conclusion.

7.0 Preliminary Determination

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Alvaro Linero, P.E., is the project engineer responsible for preparing the draft BACT determination and the permit as well as evaluating projecting the impacts on fuel supply. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

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